DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM01–12–000]

Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design

July 31, 2002.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to amend its regulations under the Federal Power Act (FPA) to modify the *pro forma* open access transmission tariff established under the Commission's Order No. 888 to remedy remaining undue discrimination in the provision of interstate transmission services and in other industry practices, and to assure just and reasonable rates within and among regional power markets. The Commission proposes to require all public utilities with open access transmission tariffs to file modifications to their tariffs to reflect non-discriminatory, standardized transmission service and standardized wholesale electric market design.

DATES: Initial comments are due on October 15, 2002. Comments should include an executive summary that does not exceed 10 pages.

ADDRESSES: Send comments to: Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

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SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's home page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Washington, DC 20426.

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I. Introduction

1. This notice of proposed rulemaking represents the third in a series of initiatives undertaken by the Commission to harness the benefits of competitive markets for the nation's electric energy customers, in order to meet our statutory responsibility to assure adequate and reliable supplies of electric energy at a just and reasonable price. In 1996, the Commission issued Order No. 888, which required, as a remedy for undue discrimination, that all public utilities provide open access transmission.[1] In 1999, the Commission issued Order No. 2000.[2] The Commission's objective was ''for all transmission owning entities in the Nation, including non-public utility entities, to place their transmission facilities under the control of appropriate regional transmission institutions [RTOs] in a timely manner.''[3]

2. Order No. 888 and Order No. 2000 set the foundation upon which to build regional transmission institutions and competitive electricity markets. However, as events have transpired, there remain significant impediments to competitive markets and to the infrastructure needed to meet our electric energy demand. Unduly discriminatory transmission practices have continued to occur and inconsistent design and administration of short-term energy markets has resulted in pricing inefficiencies that can cause rates to be unjust and unreasonable. At the same time, the nature of the electric industry has changed in a way that makes the development of competitive wholesale markets all the more critical. The electric industry has evolved from one characterized by large, vertically integrated utilities to an industry with increasing wholesale trade and increasing numbers of independent buyers and sellers of wholesale power seeking non-discriminatory access to transmission facilities. Public utilities

[1] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, 62 FR 12,274 (March 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, remanded in part on other grounds sub nom. Transmission Access Policy Study Group, et al.* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 122 S. Ct. 1012 (2002).

[2] Regional Transmission Organizations, Order No. 2000, 65 FR 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12,088 (February 25, 2000), FERC Stats. & Regs ¶ 31,092 (2000), *petitions for review dismissed,* Public Utility District No. 1 of Snohomish County, *Washington* v. *FERC,* 272 F.3d 607 (D.C. Cir. 2001).

[3] Regional Transmission Organizations, 64 FR 31,389 (May 13, 1999), FERC Stats. & Regs. ¶ 32,541 at 33,685 (1999) (Notice of Proposed Rulemaking).

today purchase significantly more wholesale power to meet their load than in the past. Indeed, from 1989 through 2000, their wholesale purchases increased from 18 percent of their total available electric energy to over 37 percent, and this percentage is expected to continue to grow.[4]

3. The Commission's objectives in this third rulemaking initiative, therefore, are to remedy remaining undue discrimination and establish a standardized transmission service and wholesale electric market design that will provide a level playing field for all entities that seek to participate in wholesale electric markets. The Commission proposes to provide new choices through a flexible transmission service, and an open and transparent spot market[5] design that provides the right pricing signals for investment in transmission and generation facilities, as well as investment in demand reduction.

4. When supply and demand do not support fully competitive markets, market design should provide protection against market power. We seek in this rulemaking to put in place sufficient regulatory backstops to protect customers against the exercise of market power when structures do not support a competitive market. Market monitoring at all times, and market power mitigation when needed, are critical pieces of this initiative.

5. A significant impediment to achieving the full benefits of competition is that there is no single set of rules governing transmission of electric energy. Not only does the Order No. 888 *pro forma* tariff contain provisions that allow different types of customers to be treated differently, but there also are conflicting state and Federal rules governing the use of interstate transmission facilities. This provides opportunities for transmission providers to establish and apply rules in a way that unduly discriminates against certain classes of customers, leads to significant transaction costs and threatens reliability.

6. To remedy undue discrimination, enhance competition, remove economic inefficiencies and ensure just and reasonable rates, terms and conditions transmission of electric energy, the Commission proposes to: Exercise jurisdiction over the transmission component of bundled retail transactions; modify the existing *pro forma* transmission tariff to include a single flexible transmission service (Network Access Service) that applies consistent transmission rules for all transmission customers—wholesale, unbundled retail and bundled retail; and provide a standard market design for wholesale electric markets. While it is critical that the same non-rate terms and conditions be applied to all transmission uses, including bundled retail, as soon as possible, we intend to work closely with our state colleagues with respect to transition issues involving bundled retail transmission rates

7. The proposed Network Access Service would combine features of both existing open access transmission services—the flexibility and resource and load integration of Network Integration Transmission Service; and the reassignment rights of Point-to-Point Transmission Service. It would give a customer the right to transmit power between any points on the transmission system—so long as the transaction is feasible under a security-constrained dispatch.

8. We expect that most if not all entities will become members of RTOs and that the new Network Access Service would be provided through these RTOs. However, this rule may become effective at a time when some transmission owners and operators have not yet become members of functioning RTOs. Thus, we propose that all transmission owners and operators that have not yet joined an RTO must contract with an independent entity to operate their transmission facilities. This proposed rule refers to both the RTO and those independent entities as ''Independent Transmission Providers.'' An Independent Transmission Provider would have no financial interest, either directly or through an affiliate, as defined in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. 79b(a)(11), in any market participant[6] in the region in which it provides transmission services or in neighboring regions. We propose that all Independent Transmission Providers administer the day-ahead and real-time markets. As discussed *infra,* we also have identified long-term planning and expansion, system impact and facilities studies and transmission transfer capability calculations (including postings on an Open Access Same-time Information System (OASIS)) as tasks that must be done on a regional basis. Thus, we propose that all Independent Transmission Providers perform these tasks.

9. In addition to creating the new Network Access Service, the revised tariff would include requirements to standardize wholesale electric market design. The fundamental goal of the Standard Market Design requirements, in conjunction with the standardized transmission service, is to create ''seamless'' wholesale power markets that allow sellers to transact easily across transmission grid boundaries and that allow customers to receive the benefits of lower-cost and more reliable electric supply. For example, currently a supplier that seeks to serve load in a distant state may need to cross several utility systems or independent system operator systems (ISOs), all of which have different rules for such things as reserving and scheduling transmission and scheduling generation. This can either result in an efficient transaction not occurring at all or it can add significant time and costs to the transaction. Standard Market Design seeks to eliminate such impediments.

10. Central to the Standard Market Design concept is its reliance on bilateral contracts entered into between buyers and sellers. The resource adequacy requirement strongly encourages such long-term contracts. The short-term spot markets set out below are intended to complement bilateral procurement. To handle generation imbalances and the procurement of ancillary services, the Commission proposes to require that all Independent Transmission Providers operate markets for energy and for the procurement of certain ancillary services in conjunction with markets for transmission service. These markets would be bid-based, security-constrained spot markets operated in two time frames: (1) A day ahead of real-time operations, and (2) in real time. The adoption of a market-based

[4] *See* Section III.C. for a more detailed discussion.

[5] The term ''spot market'' typically refers to a trade that covers a short period in the very near future. Trading in an independent transmission system operator (ISO) real-time or day-ahead market is referred to here as occurring in the spot market. In the Western price mitigation order, the Commission defined a spot market trade as any trade lasting 24 hours or less, whether a bilateral trade or a trade occurring in an organized real-time or day-ahead market that does not match up particular sellers and buyers. *See* San Diego Gas and Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange, 95 FERC ¶ 61,418 at 64,525 n.3 (2001). We will adopt this meaning for this rulemaking.

[6] A market participant means: (i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the [RTO], unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the [RTO's] actions or decisions; and (ii) Any entity that the Commission finds has economic or commercial interests that would be significantly affected by the [RTO's] actions or decisions. 18 CFR 35.34 (2) (2002).

locational marginal pricing (LMP) transmission congestion management system is designed to provide a mechanism for allocating scarce transmission capacity to those who value it most, while also sending proper price signals to encourage short-term efficiency in the provision of transmission service as well as wholesale energy, and to encourage long-term efficiency in the development of transmission, generation and demand response infrastructure. We expect that market participants will strike an appropriate balance between bilateral contracts and spot market transactions. Efficient spot markets with appropriate price signals bring bilateral and spot market prices closer together, helping to assure customers of efficient bilateral markets.

11. Several changes required by Standard Market Design promote greater customer access to low-cost power. We note that this may raise concerns that cheap power may leave one region for sale in another, higher-priced region. This can only happen with generation that is not already under contract for purchase. Thus, customers in low-cost regions can ensure that low-cost power ''stays home'' by contracting for that power. This way, only excess power will leave the region to serve another market.

12. The Commission proposes a pricing policy and process for recovering the costs of new transmission investment so as to develop the infrastructure needed to support competitive markets. The policy builds on the price signals provided by the proposed spot market design. However, there are cases where LMP price signals alone will not encourage all beneficial transmission investments. Therefore, we propose to require market participants to participate in a regional process to identify the most efficient and effective means to maintain reliability and eliminate critical transmission constraints.

13. Even with good market design rules, current supply and demand conditions make a market monitoring and market power mitigation plan necessary. The market power mitigation proposed in this rule would rely on a combination of methods to protect against the exercise of market power by preventing sellers from withholding economical supplies from the market, while permitting prices to reflect true scarcity. The proposed market power mitigation method should be more restrictive at times or places where the exercise of market power is more likely to occur than at times or places where the market is sufficiently competitive.

14. However, because market power mitigation may tend to suppress scarcity prices that signal the need for investment, a companion mechanism besides spot prices is needed. The Commission proposes a resource adequacy requirement to ensure adequate electric generating, transmission and demand response infrastructure, the level of which is to be determined on a regional basis. Recognizing that supply planning and retail customer demand response are the states' responsibility, the Commission proposes a resource adequacy requirement intended to complement existing state programs. In particular, the Commission proposes that an RTO or other regional entity must forecast the region's future resource needs, facilitate regional determination of an adequate future level of resources and assess the adequacy of the plans of load-serving entities [7] to meet the regional needs. Each load-serving entity would be required to meet its share of the future regional need through a combination of generation and demand reduction.

15. In summary, in this proceeding, the Commission, pursuant to its authority under sections 205 and 206 of the Federal Power Act,[8] proposes to:

(1) Establish a single non-discriminatory open access transmission tariff with a single transmission service (Network Access Service) that is applicable to all users of the interstate transmission grid: wholesale and unbundled retail transmission customers, and bundled retail customers;

(2) Require all public utilities that own, control or operate interstate transmission facilities to become an Independent Transmission Provider, turn over their transmission facilities to an Independent Transmission Provider or contract with an Independent Transmission Provider to operate their facilities. An Independent Transmission Provider is any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the SMD Tariff, and that is independent (*i.e.*, has no financial interest, either directly or through an affiliate, as defined in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. 79b(a)(11), in any market participant in the region in which it provides transmission service or in neighboring regions).

(3) Require that an Independent Transmission Provider provide transmission services and administer the day-ahead and real-time energy and ancillary services markets;

(4) Establish an access charge to recover embedded transmission costs based on a customer's load ratio share of the Independent Transmission Provider's costs, and would be paid by any customer taking power off the grid;[9]

(5) Use LMP as the system for transmission congestion management and provide tradable financial rights—Congestion Revenue Rights [10] as a means to lock in a fixed price for transmission service;

(6) Establish a preference for the auction of Congestion Revenue Rights, but initially allow regional flexibility for a four-year transition period in determining whether to allocate Congestion Revenue Rights to existing customers or auction such rights such that revenues are allocated to existing customers to hold them financially harmless;

(7) Establish open imbalance energy markets to allow all market participants to buy or sell their imbalances in a fair, efficient and non-discriminatory market. Imbalance markets would be neutral towards fuel sources and treat demand resources on an equal footing with supply;

(8) Permit customers under existing contracts to receive the same level and quality of service under Standard Market Design that they receive under their current contracts, to the greatest extent feasible;

(9) Establish procedures to mitigate market power in the day-ahead and real-time markets required by Standard Market Design and mechanisms for market monitoring;

(10) Establish procedures to assure, on a long-term regional basis, that there are adequate transmission, generation and demand-side resources;

(11) Provide a formal role for state representatives to participate in the

[7] A load-serving entity is an entity, including a municipal electric system and an electric cooperative, authorized by law, regulatory authorization or requirement, agreement, or contractual obligation to supply energy, capacity, and/or ancillary services to retail customers located within the transmission provider's service area, including an entity that takes service directly from the transmission provider to supply its own load in the transmission provider's service area. *See* SMD Tariff § 1.

[8] 16 U.S.C. 824d and 824e (1994).

[9] As explained in section IV.D.1, current long-term point-to-point customers that seek to receive Congestion Revenue Rights would also pay the access charge.

[10] These rights were called ''Transmission Rights'' in the Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, Docket No. RM01–12–000 (Mar. 15, 2002) (hereinafter Working Paper).

decision-making processes of Independent Transmission Providers; and

(12) Clarify the obligation of all users of the transmission system to comply with all appropriate standards for ensuring system security and reliability.

16. The Commission's focus is on promoting the development of competitive wholesale markets and we do not intend to interfere with the legitimate concerns of state regulatory authorities. It remains within a state's authority to determine whether or not to provide retail access. Nevertheless, the reforms proposed in this rulemaking will benefit customers in states with or without retail access. In addition, we seek to formally involve state representatives in the decision-making processes of regional entities. We also recognize the need to permit parties to continue to rely on existing contracts and scheduling practices, including those involving hydroelectric power, and these are fully accommodated under Standard Market Design.

17. The Commission recognizes that differences exist throughout the regions of the country; however, the Commission's goal is to remedy undue discrimination by standardizing transmission service and wholesale electric market design as much as possible. We propose to allow certain regional variations, as described *infra.*

18. Finally, the Commission recognizes that implementation of a revised open access transmission tariff and Standard Market Design on a nationwide basis may take some time. Thus, the Commission proposes a phased compliance process. By July 31, 2003, all public utilities that own, operate or control interstate transmission facilities must file revised open access transmission tariffs (Interim Tariffs) to become effective September 30, 2004, that reflect the inclusion of bundled retail customers as eligible customers. By December 1, 2003, all public utilities that own, control or operate interstate transmission facilities must file revised open access transmission tariffs (SMD Tariffs), to become effective no later than September 30, 2004, or such other time as directed by the Commission, that reflect all of the remaining revisions and requirements of the Final Rule in this proceeding. The Commission and its staff will work with regional organizations and stakeholders in facilitating full and efficient compliance with this rule.

19. Below in Section II we set out the relevant developments in the electric industry. In Section III and Appendix C we explain the need for further reform. In Appendix E, we discuss various allegations of market manipulation strategies encountered in the organized markets and how Standard Market Design will address these strategies. In Section IV we explain our specific remedy for pervasive problems in the industry consistent with our statutory responsibilities. In Section V, we set out the implementation process and dates. Finally, the glossary for the terms used in this document is found in the Definitions section of the SMD Tariff in Appendix B, and the revisions to the Interim Tariff are set out in Appendix A.

II. Background: Order No. 888 and Order No. 2000

A. Order Nos. 888 and 888–A

20. In April 1996, in Order No. 888, the Commission found that unduly discriminatory and anticompetitive practices existed in the electric industry, and that public utilities that own, control or operate interstate transmission facilities had discriminated against others seeking transmission access. It determined that non-discriminatory open access transmission services, including access to transmission information, and stranded cost recovery were the most critical components of a successful transition to competitive wholesale electricity markets.[11] The Commission stated that its goal was to ensure that customers have the benefits of competitively priced generation.

21. Order No. 888 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to: (1) File open access non-discriminatory transmission tariffs containing certain minimum, non-price terms and conditions, and (2) functionally unbundle wholesale power services from transmission services.[12] Functional unbundling requires public utilities to: (1) Take wholesale transmission services under the same tariff of general applicability as they offer their customers; (2) state separate rates for wholesale generation, transmission, and ancillary services; and (3) rely on the same electronic information network that their transmission customers rely on to obtain information about the utilities' transmission systems.[13] In Order No. 889, issued concurrent with Order No. 888, the Commission also imposed standards of conduct governing communications between the utility's transmission and wholesale power functions, to prevent the utility from giving its power marketing arm preferential access to transmission information.[14] Under Order No. 889, all public utilities that own, control or operate facilities used in the transmission of electric energy in interstate commerce are required to create or participate in an OASIS that provides existing and potential transmission customers the same access to transmission information that will enable them to obtain open access non-discriminatory transmission service.

22. The Commission declined to require corporate unbundling at the time of Order No. 888, and stated instead that efforts to remedy undue discrimination should begin by requiring the less intrusive functional unbundling approach.[15] While the Commission in Order No. 888 encouraged the creation of ISOs and set forth eleven principles for assessing ISO proposals submitted to the Commission, it did not mandate regional organizations.[16] The Commission in Order No. 888 stated:

> [W]e see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace. As a further precaution against discriminatory behavior, we will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, we will analyze all alternative proposals, including formation of ISOs, and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, we will reevaluate our position and decide whether other mechanisms, such as ISOs, should be required. [17]

Order No. 888–A reaffirmed the findings of Order No. 888. The Court of Appeals for the District of Columbia Circuit upheld the orders "in nearly all respects." [18] The Supreme Court recently affirmed.[19]

23. A number of significant developments took place in the electric utility industry following issuance of Order No. 888. All public utilities filed non-discriminatory, open access transmission tariffs stating rates, terms and conditions for comparable

[11] *See* Order No. 888 at 31,652.

[12] *See id.* at 31,635–36.

[13] *See id.* at 31,654.

[14] *See* Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 FR 21,737 (April 24 1996), FERC Stats. & Regs. ¶ 31,035 at 31,588–91 (1996), *order on reh'g,* Order No. 889–A, 62 FR 12,484 (March 4, 1997), FERC Stats. & Regs. ¶ 31,049 (1997).

[15] *See* Order No. 888 at 31,654.

[16] *See* id. at 31,730–32.

[17] *Id.* at 31,655.

[18] Transmission Access Policy Study Group, 225 F.3d at 681.

[19] *See New York* v. *FERC,* 122 S.Ct. 1012.

wholesale transmission service to third-party users of their transmission systems. With the advent of OASIS systems, improved information about transmission systems became available to all participants in the bulk power market at the same time that it was available to utilities' own wholesale merchant functions and wholesale marketing affiliates (although further information improvements are still needed). New generation resources were developed in areas that had experienced generation shortages.[20] Regional trading patterns have expanded. In addition, the Commission granted a large number of merger applications and applications to charge market-based rates, effecting structural changes in the industry. The industry thus became less localized and more regionalized, with a growing need for regional planning and regulation. And as part of that regionalization, the Commission also approved voluntary ISOs in five regions of the country—New England, New York, PJM,[21] the Midwest and California (an ISO was also formed in ERCOT, but it is not under the Commission's full jurisdiction). These ISOs are the precursors to regional entities identified as RTOs, in the Commission's Order No. 2000, discussed below.

B. Order No. 2000

24. Order No. 2000, issued in December 1999, was the Commission's second major step toward establishing competitive wholesale power markets and eliminating residual undue discrimination in interstate transmission services. It identified two broad categories of impediments to competitive electricity markets: (1) The engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid, and (2) continuing opportunities for transmission owners to unduly discriminate in the operation of their transmission systems so as to favor their own (or their affiliates') power marketing activities.[22] Further, evidence indicated that local management of the transmission grid by many individual vertically integrated utilities was inadequate to support the efficient, reliable regionwide operation that was needed for continued development of competitive markets. The Commission concluded that establishing independent RTOs would eliminate residual undue discrimination in transmission, enhance the benefits of competitive electricity markets, and could: (1) Improve efficiency in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter-handed regulation. The Commission anticipated that formation of regional transmission grids would result in a substantial cost savings to the electric utility industry and its customers.[23]

25. Order No. 2000 encouraged all transmission owners to voluntarily place their transmission facilities in the hands of appropriate RTOs. The Commission stated that RTOs could include ISOs or independent for-profit transmission companies (ITCs). However, all RTOs must meet four minimum characteristics and eight minimum functions that were identified in Order No. 2000, and also must have an open architecture framework that would permit an RTO and its members flexibility to improve their structures over time.[24]

26. Following Order No. 2000, some transmission-owning public utilities began to file proposals to participate in RTOs. The process has been slow for several reasons, one of which is stakeholder uncertainty about what the Commission would require for RTO approval—not only for the RTO scope and independence characteristics, but also regarding such RTO functions as congestion management and market-oriented provision of ancillary services.

27. Order No. 2000 called for RTOs to be in operation across the nation by December 2001. To date, there is only one RTO fully approved by the Commission, the Midwest ISO, which began operating in early 2002.[25] The Midwest ISO is large. It stretches from an eastern boundary in western Pennsylvania westward to the Rocky Mountains, northward into Manitoba, Canada and southward to the Texas border.

28. Although progress with Commission-approved RTOs has been slow, regionalization has also occurred through the ISO formation process that was encouraged in Order No. 888. The Northeast and California ISOs are engaged in a process to become Commission-approved RTOs or to join larger RTOs. In eastern North America, close coordination is developing between U.S. and Canadian transmission systems and market designs.

29. In addition to the Midwest ISO, the Commission has provisionally approved other RTOs,[26] and authorized operation of ITCs that operate under an RTO umbrella.[27] The Commission also ordered Northeastern and Southeastern RTO applicants, including some applicants whose RTO proposals had been provisionally approved, into mediation proceedings to facilitate the formation of RTOs in those areas.[28] The Commission further noted that a ''west wide RTO, or a seamless integration of Western RTOs, is the best vehicle for designing and implementing a long-term regional solution'' to the West's electric generation supply crisis.[29]

[20] *See* Staff Report to the Federal Energy Regulatory Commission on the Causes of the Pricing Abnormalities in the Midwest During June 1998 (1998), *available in http://www.ferc.gov/electric/mastback.pdf.*

[21] The PJM ISO takes its name from the former Pennsylvania, New Jersey, Maryland Power Pool, which serves New Jersey, Maryland, Delaware, much of eastern Pennsylvania, the District of Columbia, and a small area of Virginia.

[22] Order No. 2000 identified four specific areas of concerns: (1) Calculation and posting of Available Transfer Capability in a manner favorable to the transmission provider; (2) standards of conduct violations; (3) line loading relief and congestion management; and (4) OASIS sites that are difficult to use. See Order No. 2000 at 31,005 n.69. The order also identified parallel path flows, planning and investing in new transmission facilities, pancaking of access charges, the absence of secondary markets in transmission service and the possible disincentives created by the level and structure of transmission rates. *See id.* at 31,014.

[23] *See id.* at 30,993.

[24] The four RTO characteristics are: (1) Independence; (2) scope and regional configuration; (3) operational authority; and (4) short-term reliability. The eight RTO functions are: (1) Tariff administration and design; (2) congestion management; (3) parallel path flow; (4) ancillary services; (5) OASIS, Total Transfer Capability and Available Transfer Capability; (6) market monitoring; (7) planning and expansion; and (8) interregional coordination. *See* Order No. 2000 at 30,993–94.

[25] *See* Midwest Independent System Operator, Inc., 97 FERC ¶ 61,326 (2001).

[26] *See* GridSouth Transco, LLC, 94 FERC ¶ 61,273 (2001); GridFlorida, LLC, 94 FERC ¶61,363 (2001); and PJM Interconnection, LLC, 96 FERC ¶61,061 (2001).

[27] *See* TRANSLink Transmission Company, L.L.C., *et al.,* 99 FERC ¶61,106 (2002) (authorizing operation of ITC within the Midwest ISO), *reh'g pending,* [Docket Nos. EC01–156–001 *et al.;* Alliance Companies, *et al.,* 99 FERC ¶61,105 (2002) (authorizing the operation of an ITC).

[28] *See* Regional Transmission Organizations, 96 FERC ¶61,065 (2001) (initiating mediation proceedings between Northeastern RTO applicants); Regional Transmission Organizations, 96 FERC ¶61,066 (2001) (initiating mediation proceedings between Southeastern RTO applicants).

[29] Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶61,272 at 61,974 (2001). A coalition of Western utilities (RTO West Filing Utilities) filed a proposal on October 16, 2001 to create RTO West. The Commission granted several of the RTO West Filing Utilities' requests for declaratory order on April 26, 2001, finding some of RTO West's proposed characteristics and functions compliant with Order No. 2000. *See* Avista Corporation, *et al.,* 95 FERC ¶61,114 (2001). The RTO West Filing Utilities then filed a proposal for Stage 2 of RTO West's creation on March 28, 2002. The Stage 2 proposal is intended to enable the Commission to determine whether the RTO West proposal fulfills all of the Order No. 2000 characteristics and functions. *See* Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000 at 5, Docket No. RT01–35–000 (Mar. 28, 2002).

30. The following section and related Appendix C discuss specific features of today's wholesale electricity markets that inhibit the development of competition and efficient regional markets, and identify areas in which the Commission must direct reforms to eliminate remaining undue discrimination and inefficiencies, and ensure just and reasonable rates.

III. Need for Reform

A. Undue Discrimination and Impediments to Competition Remain

31. Since the issuance of Order Nos. 888 and 2000, it has become clear that additional, mandatory measures are needed to achieve the goals of non-discriminatory transmission access and competition in electricity markets. Vertically integrated transmission owners and operators continue to use their interstate transmission facilities in ways that inhibit competition in wholesale power markets as well as competition in those retail power markets where states have adopted retail choice. The discriminatory preferences that these transmission owners and operators give to their own uses of the interstate transmission grid to serve their retail customers (whether or not they are in retail choice states) results in discrimination against, and in costs being borne by, other wholesale and retail customers who also rely on the interstate transmission facilities to buy power. The discriminatory preferences also create barriers to new sellers that could provide lower-cost power. This could result in higher prices to the native load served by the transmission owner. For example, transmission-dependent utilities [30] and other load-serving entities need the interstate transmission facilities to move power they are purchasing by contract from distant generators or suppliers, but allege that despite the requirements of Order No. 888, they are denied comparable access to the grid. Similarly, new generators wishing to compete in wholesale markets or for retail customers in retail choice states tell us that they are denied comparable access to the grid, thus inhibiting entry of new, lower-cost, efficient and environmentally superior power suppliers.

32. The Commission recently has taken additional steps to address some of the remaining impediments to non-discriminatory transmission access and competition in wholesale power markets. For example, the Commission's recently issued Generator Interconnection proposed rule seeks to remove one particular type of undue discrimination occurring in the marketplace—barriers to obtaining interconnections to the interstate transmission grid—so that new generators can compete with vertically integrated transmission providers to serve load.[31] However, this initiative will resolve only one aspect of remaining discriminatory practices. Other opportunities for vertically integrated transmission providers to operate in ways that favor their own generation remain within the construct of the pro forma tariff (*e.g.*, preferences for native load and network customers to reserve transmission capability, differing transmission services that raise barriers to competition, the lack of inclusion of all services under the same tariff). As noted in Order No. 2000, "perceptions of discrimination are significant impediments to competitive markets. Efficient and competitive markets will develop only if market participants have confidence that the system is administered fairly."[32]

33. Furthermore, it has become apparent that there are also opportunities to discriminate and to hinder an efficient, competitive marketplace due to the absence of standardization with respect to market rules and practices within and between regional markets. So-called "seams" problems (*e.g.*, different rules and different pricing systems) create transaction costs and artificial barriers to trade. These problems inhibit the Commission from fulfilling its statutory responsibility to ensure that customers receive reliable power supplies at the lowest reasonable costs.[33]

34. Finally, innovation that the Commission expected to see with respect to new service offerings has been sporadic and unsteady. Innovations in transmission control and pricing (*e.g.*, ISO control of transmission and LMP for generation and transmission services in the Northeast, RTO formation in the Midwest), while impressive, have been slow to take root in other regions of the country. The *pro forma* tariff was envisioned as the baseline above which transmission providers were encouraged to develop competitive and customer-responsive service offerings. But Florida Power Corporation's network contract demand service, a hybrid of Network Integration Transmission Service and Point-to-Point Transmission Service features,[34] and Duke Energy Corporation's "recallable long-term firm" service [35] are the only noteworthy new services accepted by the Commission for use with a single utility's open access transmission tariff. Other proposed *pro forma* tariff revisions amounted to little more than working around the edges of the existing services and procedures and did not produce more competitive transmission service that reduces overall electricity costs.

35. Most ISOs recently introduced centralized short-term real-time hourly markets and day-ahead markets for energy (*i.e.*, spot markets) where sellers sell into the market and buyers buy from the market without matching a particular seller with a particular buyer. In such organized spot markets, there is a single market clearing price established that is received by all generators who bid into the market below that price and is paid by all load that bids in above that price. However, the ability of customers to bid demand reductions into the spot market in response to supplier prices is still limited and needs to be improved significantly for short-term markets to operate more competitively. Further, while there have been benefits of market development in the Northeast (PJM, New York ISO, ISO-New England), Texas and California (during the first two years of its restructuring), the Midwest ISO is still in the formative stages of operation with respect to markets, and few market benefits have materialized in the Southeast and West.

B. Specific Instances of Undue Discrimination and Impediments to Competition

36. The specific reasons for requiring reform are many. Market participants

[30] A transmission-dependent utility is a utility that does not own generation and relies on its neighboring utilities to transmit power to it that it purchases from its suppliers.

[31] See Standardization of Generator Interconnection Agreements and Procedures, 67 FR 22,249 (May 2, 2002), FERC Stats. & Regs. ¶32,560 at 34,174 (2002) (Notice of Proposed Rulemaking). The proposed rule defines interconnection study time frames and grants all generators the opportunity to be treated as competing network resources in meeting load and load growth. *See id.* at 34,243–45.

[32] Order No. 2000 at 31,017. Lack of market confidence may lead to a reluctance on the part of market participants to share operational real-time and planning data with transmission providers because of the suspicion that they could be providing a competitive advantage to their affiliated power marketers. It may also deter generation expansion and lead to the perception that the transmission provider's generation is more reliable, thereby reducing competition and raising prices for customers. *See id.*

[33] *See FPC* v. *Hope Natural Gas Company,* 320 U.S. 591, 610 (1944).

[34] *See* Florida Power Corporation, 81 FERC ¶ 61,247 (1997).

[35] *See* Duke Energy Corporation, 88 FERC ¶ 61,184, reh'g denied, 89 FERC ¶ 61,190 (1999).

have identified, through formal complaints, hotline calls, public conferences, and pleadings, the difficulties they have experienced in gaining equal access to the transmission grid to compete with vertically integrated utilities to serve load. Much of this problem is directly attributable to the remaining ability of such vertically integrated utilities (and the existence of sufficient incentives) to exercise some degree of transmission market power in order to protect their own generation market share. Further complicating transmission access is the fact that not all transmission service is provided under the rates, terms and conditions of the Commission's *pro forma* tariff. Rather, over 60 percent of load has been subject to various state rules governing the transmission component of bundled retail transactions. Independent transmission service under a common set of rules would solve many of these problems.

37. Nevertheless, new problems have been created by some of the market design experiments. In regions of the country where the separation of transmission from generation has been addressed through the creation of ISOs (which, in some instances, have placed nearly all load under a single tariff), market design flaws create inefficiencies in the marketplace and opportunities for the exercise of market power. Conflicting market rules and procedures in neighboring ISOs have created or perpetuated seams problems that impede the economic flow of power from one region to another. All of these problems have hindered the progress towards competitive regional electricity markets. Standard Market Design is intended to address these problems.

1. Transmission Market Power by Utilities That Are Not Independent

38. By differing means, Order Nos. 888 and 2000 attempt to effect open access transmission by reducing the ability of transmission owners that also own generators to act in anticompetitive or unduly discriminatory ways against other generators. In both orders, the Commission attempted to move the electric industry into a competitive wholesale market without mandating corporate restructuring. Through Order Nos. 888 and 2000, the Commission required open access to public utility transmission systems, encouraged the formation of ISOs and, later, RTOs to achieve control of the transmission grid by entities that are independent from generation marketing or sales. However, only limited portions of the country have moved beyond the basic requirements of open access (*e.g.*, through the voluntary divestiture of generation or establishment of RTOs, ISOs, or ITCs). In the rest of the country, the remaining corporate ties between generation and transmission within public utilities have proven problematic for transmission access. Thus, across most of the nation, barriers to entry remain for new generators and new load-serving entities.

39. A large portion of this problem is directly attributable to the continued ability of vertically integrated transmission providers to exercise some degree of transmission market power to advantage their own or affiliated generation. The longer the vertically integrated transmission provider can use access to interconnection or transmission service to delay or prevent entry of competing generators to its service territory, the longer it can profit from its own generation sales with a limited threat of competition. Vertically integrated transmission providers have found numerous ways to delay or prevent entry of competitors, some within the existing rules and some by exceeding reasonable discretion afforded to the transmission provider. All of these are difficult to monitor or prevent with behavioral rules.[36]

40. As part of Standard Market Design, we propose that an Independent Transmission Provider operate all transmission facilities. The requirement for independent control of the transmission grid, preferably by an RTO, resolves these types of problems.

a. Load Growth

41. Under the current *pro forma* tariff, a transmission provider is required to plan its system to allow customers with existing long-term contracts to extend, or roll over, those contracts.[37] However, the transmission provider has a right to recall that transmission capacity if it identified in the initial agreement with the customer that it had projected native load growth that would require that transmission capacity.[38] Transmission providers have failed to identify any native load growth at the time of the initial agreement, and disputes have arisen with customers claiming they were denied the ability to roll over their contracts because the transmission provider claimed, well after the contract was executed, that the transmission capacity at issue was required to serve native load growth.[39]

42. In Standard Market Design, we propose to eliminate the preference for future native load growth. Instead, since Congestion Revenue Rights will be used to assure price certainty, Congestion Revenue Rights will be apportioned based on historical use or by an auction, neither of which grants preference for future load growth by a particular supplier; this approach resolves these concerns.

b. Delays in Responding to Requests for Service

43. Another type of anticompetitive behavior centers on a vertically integrated transmission provider delaying the processing of a competitor's request for new transmission service or interconnection (including the related system impact or facilities studies). Transmission providers have done so by failing to follow time lines or expansively interpreting the tariff procedures. These delays may be enough to cause the competing generator to lose the sale, particularly if the potential customer is concerned that it may lose service completely if it does not stay with the transmission provider.[40]

44. Under Standard Market Design, these types of delays are resolved through the requirement for an independent entity, preferably an RTO, to perform studies and calculate available transfer capability (ATC),[41] since an independent entity would have no incentive to favor one customer over another.

[36] *See* Working Paper at 21 (Mar. 15, 2002); *see also* Comment of the Staff of the Bureau of Economics and Office of General Counsel of the Federal Trade Commission, Docket No. RM01–12–000 (July 23, 2002).

[37] *See* Section 2.2 of the current *pro forma* tariff.

[38] *See* Order No. 888–A at 30,277.

[39] *See Public Service Company of New Mexico* v. *Arizona Public Service Co.,* 99 FERC ¶ 61,162 (2002), for a recent example. In this case, the Commission directed APS to grant PSNM's request to extend its contract for 60 MW of Point-to-Point Transmission Service. APS had attempted to deny the rollover request on the basis that it had verbally informed PSNM that capacity would not be available due to APS's future native load growth. The Commission restated the principle that a transmission provider can deny a customer the ability to roll over its long-term firm service contract only if the transmission provider includes in the service agreement a specific limitation based on reasonably forecasted native load needs that will use the transmission capacity provided under the contract at the end of the contract term.

[40] *See Kinder Morgan Power Co.* v. *Southern Company Services, Inc.,* 97 FERC ¶ 61,240 (2001), *reh'g denied,* 98 FERC ¶ 61,044 (2002) (finding Southern's interconnection procedures delayed and discriminated against customer's ability to develop new projects).

[41] 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 transmission services. To be consistent with the term generally accepted throughout the industry, ''Available Transfer Capability'' will be used.

c. Scheduling Advantages

45. A vertically integrated transmission provider has a structural advantage over many competitors to make economy sales or to serve its own load, primarily because it has a large portfolio of both generators and loads. A competitor with access only to generation outside of the control area and no native load has to identify the delivery point of its power before being able to secure transmission service. But a vertically integrated transmission provider does not have to identify a specific location on the grid to serve its load because its load is dispersed across its entire system. A vertically integrated transmission provider also does not have to identify a single generation location, but can run a combination of its own generators or purchase from lower cost-suppliers inside or outside of its system. It can schedule purchased power to one of its own loads (in place of power from one of its own generators) in order to secure transmission service for the purchase. Later, it can find a buyer for the power and schedule transmission service from one of its internal generators to the load. This often is enough of a scheduling advantage over a competing supplier to ensure that the transmission provider (or its affiliated power marketer) gets the sale.

46. While it is true that all network customers have these same rights and abilities, in many areas of the country the only customer using network service is the vertically integrated transmission provider. Moreover, the vertically integrated transmission provider's size of resources and loads is usually much greater than any other network customer, giving it that much more of an advantage in flexibility. In addition, the vertically integrated transmission provider may have an advantage through access to better or more transmission and other related information.

47. Under Standard Market Design, all transmission service will be provided under a new Network Access Service. Having one service for all customers will eliminate scheduling advantages of competing suppliers.

d. Imbalance Resolution

48. Customers have also alleged that vertically integrated transmission providers have an advantage over competitors in the resolution of energy imbalances. Transmission providers with generation and load of their own can resolve their own energy imbalances through in-kind energy exchanges with neighboring systems. In contrast, other customers of the transmission provider face higher costs if they take service from other suppliers that could balance against each other. This difference gives the transmission provider a competitive advantage over other sellers of power.

49. Under Standard Market Design, all suppliers and loads on a system will resolve imbalances through the same energy imbalance procedures. This will remove any competitive advantage the transmission owner with its own generation and load may have over competing power suppliers.

e. Available Transfer Capability and Affiliates

50. Another source of discrimination is the calculation of Available Transfer Capability. A transmission provider that is not independent calculates its Available Transfer Capability, using its own proprietary data and its own equations. This discretion gives it the ability and the opportunity to discriminate in its own favor against entities that rely upon the OASIS for Available Transfer Capability information. In several cases, the Commission has found that utilities' OASIS postings reflect an inaccurate Available Transfer Capability. Indeed, in response to ''serious concerns about the integrity of the postings of ATC'' on the OASIS systems of two transmission providers, the Commission required the transmission providers to employ an independent third party to administer their OASIS systems.[42]

51. Under Standard Market Design, an independent entity will calculate Available Transfer Capability and schedule transmission service. This will eliminate this potential for undue discrimination.

f. OASIS Postings

52. Manipulation or violation of OASIS posting requirements and the Commission's standards of conduct is another way vertically integrated transmission providers that control their own OASIS sites are able to engage in undue discrimination. This can occur through prohibited off-OASIS communications between the transmission provider and its affiliated market participant, *e.g.*, informing only the affiliate about Available Transfer Capability that will soon become available and posted on the OASIS so that the affiliate will be first in line to claim the capability.[43] Such abuses reinforce our belief that, in the absence of an independent entity calculating Available Transfer Capability and operating a transmission provider's OASIS, ''a transmission provider's self-monitoring of its standards of conduct is not sufficient, and that it is essential for interested parties to be able to participate in this process'' of reviewing communications between market participants.[44] Further, even with the best of intentions, it is not possible for a single transmission provider in a region to calculate Available Transfer Capability on its system alone without accounting for the transactions over all the other systems in its region and neighboring regions.

53. Similarly, control over the design, function and maintenance of OASIS systems may also present opportunities for discrimination. The Commission has been concerned for some time that transmission providers have the ability to impede competition by making their OASIS sites difficult to use, limiting users' access to OASIS and limiting access to information about transmission curtailments and interruptions that would allow the Commission to identify instances of undue discrimination.[45]

54. Under Standard Market Design, an independent entity will operate an OASIS on a regional basis, and thus will remove any advantages one seller may have over another and improve the accuracy of regional Available Transfer Capability postings on the OASIS.

g. Capacity Benefit Margin Manipulation

55. The Commission has found instances of transmission providers taking advantage of their ability to reserve interface capability to serve their

[42] *See* AEP Power Marketing, Inc., *et al.*, 97 FERC ¶ 61,219 at 61,973 (2001), *reh'g pending*, Docket Nos. ER96–2495–016, *et al. See also* American Electric Power Company, Inc. and Central and South West Corporation, 90 FERC ¶ 61,242 at 61,789 (2000) (requiring AEP to turn over its OASIS and ATC calculation functions to an independent entity as a condition of the applicants' merger). *See also* Appendix C for other examples.

[43] *See Aquila Energy Marketing Corporation* v. *Niagara Mohawk Power Corporation,* 87 FERC ¶ 61,328 (1999) (finding that off-OASIS communication between utility and its marketing affiliate led to preferential treatment of the affiliate); The Washington Water Power Company, 83 FERC ¶ 61,097 (1998) (finding favorable treatment of affiliate and expressing concern that this treatment may have been the result of prohibited off-OASIS communication).

[44] *Aquila Energy Marketing Corporation* v. *Niagara Mohawk Power Corporation,* 87 FERC ¶ 61,238 at 62,279 (1999).

[45] *See* Regional Transmission Organizations, FERC Stats. & Regs. ¶ 32,541 at 33,713 (describing market participants' perceptions that transmission providers may use OASIS to discriminate among market participants); Open Access Same-Time Information System, 64 FR 34,117 (June 25, 1999), FERC Stats. & Regs. ¶ 31,075 (1999) (articulating changes to Commission regulations that would make available more information about transmission curtailments and interruptions and limit OASIS hosts' ability to disconnect users).

own load while limiting the ability of competing suppliers to access customers on its system. For instance, transmission providers have reserved excessive amounts of capacity benefit margin (CBM) to serve their own load,[46] and violated the *pro forma* tariff by reserving large amounts (*e.g.*, 2,000 MW) of transfer capability at multiple interfaces, under the label of ''firm import for native load,'' without designating resources or loads associated with the reservations as other transmission customers are required to do.[47] Import capability reserved by the transmission provider blocks a competing supplier from securing firm service across the interface, limiting that supplier's ability to compete to serve load on the system, or on neighboring systems. A related issue is whether those who set aside transmission for CBM are reserving it and paying for it under the terms of the *pro forma* tariff. When transfer capability for CBM is set aside for the use of one market participant, its cost is not necessarily allocated to that market participant alone. Because transmission facility embedded costs are allocated to transmission customers on the basis of use—capacity reservation for Point-to-Point Transmission Service customers and load ratio share (which does not include the transmission capability set-aside of CBM) for Network Integration Transmission Service customers—all customers may unfairly subsidize the cost of the CBM capability.

56. Under Standard Market Design, entities that want to reserve transfer capability must pay for that capability to reach generation reserves across an interface. Thus, the preferential treatment would be eliminated.

h. Discretionary Use of Transmission Loading Relief

57. The opportunity for anticompetitive behavior arises when transmission providers have discretion to dispatch their own generation to serve their own load in a way that requires transmission service curtailments through the use of transmission loading relief (TLR) procedures.

58. There has been a sharp increase in the number of TLRs used in some regions, suggesting that transmission operators rely upon them to do more than simply relieve emergency transmission overloads.[48] There are unmistakable financial incentives to rely on TLRs in forward transmission planning:

> The increased incidence of TLRs may suggest that some transmission capacity is being oversold. Market participants have attributed a tendency to implement a greater number of TLRs to the commercial reality that transmission providers do not have to refund transmission reservation fees for service curtailed because a TLR is called.[49]

59. When a vertically integrated transmission provider injects power from its own generation onto its own power lines to meet the constantly shifting demands of the load on its system, it has both the opportunity and the incentive to manipulate the transmission system for its own benefit. It can either dispatch generators to create a transmission constraint that prevents a competitor from making a sale that the transmission provider would also like to make, or it can capitalize on legitimate constraints into a load pocket to curtail a competitor's transmission transaction and serve the customer with its own generation instead. The key here is that none of the transmission provider's actions require direct communication with its merchant function or marketing affiliate. A simplified hypothetical example of such anti-competitive behavior is set forth in Appendix C.

60. Several aspects of our proposed remedy address this concern, including the use of LMP to manage congestion and the requirement that transmission facilities be operated by an Independent Transmission Provider.

2. Lack of Common Rules Governing Transmission

61. Some of the difficulties that come from having different rules as power moves across the grid are discussed later in the Seams Problems Section III.B.4), where a ''seam'' is a dividing line between different sets of grid rules.

62. Having two or more different sets of rules governing the operation of a transmission system makes it difficult—if not at times impossible—for that system to support an efficient regional electric power market. If the interstate transmission system is to provide fair and efficient movement of power on behalf of all users of the system, the same general rules must govern such matters as who gets service, who has the right to transmission service when not all service requests can be accepted, how the transmission facility costs are allocated among transmission customers, who gets its transmission curtailed and by how much when a transmission outage prevents all the planned services from being accommodated, who plans the additions to the grid and who pays for these additions.

63. Today there are not only different rules in different public utility systems, but there may be more than one set of rules for transmission owned by a single utility. This is because there are different rules for two types of wholesale transmission service, and the rules for bundled retail transmission service may differ from the rules for wholesale and unbundled retail transmission services.

64. The Commission established an open access transmission tariff under Order No. 888 that provides for two distinct types of wholesale transmission services—Network Integration Transmission Service and Point-to-Point Transmission Service. Network Integration Transmission Service was designed primarily to meet the needs of the transmission customer that wants to integrate many generators and many loads at diverse locations on the public utility's grid; it was intended to be comparable to the service that the public utility provided to its own bundled retail customers. Point-to-Point Transmission Service, as the name implies, was designed primarily for the customer that wants to move power from one discrete location to another.

65. At the time Order No. 888 issued, the Commission recognized the potential for problems with having two wholesale services that could not be truly equal, especially the problem of dealing with claims of undue discrimination between the services.

[46] *See* Delegated Letter in Docket No. ER98–4410–000 (Feb. 8, 1999); Entergy Services, Inc., 87 FERC ¶ 61,156 (1999) (directing Entergy, which had reserved 2900 MW, to recompute ATC).

[47] *See Aquila Power Corporation* v. *Entergy Services, Inc.,* 90 FERC ¶ 61,260, *reh'g denied,* 92 FERC ¶ 61,064 (2000), *appeal docketed,* No. 00–1417 (D.C. Cir. Sept. 22, 2000). The Commission did not order a remedy in the complaint docket since the compliance filing in Docket No. ER98–4410 to remedy the excessive native load reservations would also provide a remedy for the improper native load reservations at the interfaces. *See id.* at 61,860.

[48] In the Southeast, the incidence of TLRs increased 354 percent from the summer of 1999 to the summer of 2000. *See* Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States (Nov. 1, 2000), *available in <http://www.ferc.gov/electric/bulkpower/southeast.pdf>,* at 3–38. In the Midwest, the incidence increased 472 percent over the same time period. *See* Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States (Nov. 1, 2000), *available in <http://www.ferc.gov/electric/bulkpower/midwest.pdf>,* at 2–32. The lack of a centralized market, particularly in the Southeast, has limited market liquidity and, thus, increased the likelihood of TLRs.

[49] Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States (Nov. 1, 2000), *available in <http://www.ferc.gov/electric/bulkpower/southeast.pdf>* at 3–39.

Consequently, along with the issuance of Order No. 888 the Commission proposed a rule to create a new tariff, called the Capacity Reservation Tariff.[50] It was intended to remedy the anticipated problems by establishing a new tariff that would replace the two wholesale services with one. The Commission received many comments on the proposed rule and held a technical conference with representatives of diverse stakeholders.[51]

66. Some parties expressed concern about moving quickly to a single service based on the Capacity Reservation Tariff model, while other parties asserted that, although a single tariff reducing the two services to one was a good policy, there were problems with the particular Capacity Reservation Tariff that was proposed. They recommended that the Commission delay acting on the proposed rule until it learned the best form of single service tariff through industry experience with open access. This is the approach that the Commission in effect followed. Since the two Order No. 888 services were adopted, however, there have been allegations of undue discrimination between customers of the two services as discussed later in this section.

67. There are also different rules for bundled retail transmission service and for wholesale and unbundled retail transmission services. States have historically established the rules for the transmission component of bundled retail transactions, while the Commission has established the rules for wholesale and unbundled retail transmission services.

68. Despite the requirement in Order No. 888 that no transmission customer may have any undue advantage over another, there remain real or perceived advantages for the customers of vertically integrated transmission owners. In many cases, the perceived advantage is one of Network Integration Transmission Service over Point-to-Point Transmission Service, where Network Integration Transmission Service is available to both bundled retail transmission customers and wholesale Network Integration Transmission Service customers, while Point-to-Point Transmission Service is taken primarily for wholesale transmission by independent power producers and marketers.

69. Four prominent examples highlight the alleged advantages that a public utility's bundled retail customers have over wholesale and unbundled retail customers. First, certain reliability practices related to keeping the transmission system balanced may allow a public utility that is responsible for keeping generation and load in balance to obtain lower costs for its own power customers. Second, a transmission-owning public utility may have more *de facto* flexibility to designate transmission receipt and delivery points than other transmission customers, if that public utility also provides power to customers on its transmission system. Third, the bundled retail customers of a transmission owner may have certain transmission reservation and pricing advantages regarding transmission transfer capability set aside for reliability. Fourth, state transmission curtailment rules that favor a public utility's bundled retail customers may conflict with the Commission's transmission curtailment rules, resulting in a transmission preference to customers in one state over customers served in other states.[52] The first three of these were summarized above, and a detailed discussion with examples is set forth in Appendix C.

70. The requirement for all services on the transmission grid to be taken under a common set of rates, terms and conditions will resolve these concerns.

3. Congestion Management

71. Due to new transmission usage patterns and the lack of transmission infrastructure improvements, congestion has increased. However, economically sound congestion management plans do not exist in most parts of the country, and transmission customers have been exposed to transmission service interruptions and increasing generation costs due to the risk of interruption. The operating rules that do exist were not designed as a congestion management tool for allocating scarce transmission capacity, but were designed to keep facilities from overloading in an emergency, such as when a transmission facility unexpectedly goes out of service.

72. Currently, under the existing *pro forma* tariff, congestion is managed primarily through a system of physical reservation of capacity, based on each individual transmission provider's calculation of the Available Transfer Capability of its grid, a calculation often made without knowledge of the power flows on its grid that result from transactions scheduled over other grids in its region. Under the current *pro forma* tariff, customers reserve capacity on either a firm or non-firm basis, based on the assumed contract path that the transaction will use. Once the customer has reserved capacity on a firm basis, it is supposed to receive certainty both that power will be delivered and the price that the customer will be charged for transmission. If the customer has non-firm capacity, it has no certainty that capacity will be available to deliver power, but does know that there will be no congestion charge if the delivery does occur.

73. The existing *pro forma* tariff also provides that the redispatch of a transmission provider's generating units to relieve congestion is required only if it can be achieved while maintaining reliable operation of the transmission system in accordance with prudent utility practice. The recovery of the higher generation costs resulting from such generator redispatch, which are a subset of opportunity costs, requires that (1) a formal generator redispatch protocol be developed and made available to all transmission customers and (2) all information to calculate redispatch costs be made available to the customer for audit. If a transmission provider collects revenues to cover the redispatch costs from a specific transmission customer, it must credit these revenues to the cost of fuel and purchased power expense included in its wholesale fuel adjustment clause. Various tariff provisions specify how redispatch is to be implemented. For instance, Sections 33.2 and 33.3 of the existing *pro forma* tariff provide that the redispatch of all network resources and the transmission provider's own resources, on a least-cost basis without regard to ownership, is to be performed only to maintain system reliability, not for economic reasons. Under those circumstances, the redispatch costs would be shared among the network customers and the transmission provider on a load ratio basis. Sections 13.5 and 27 of the existing *pro forma* tariff permit the transmission provider to provide the requested transmission service and relieve a system constraint by redispatching the transmission provider's resources: (1) If this costs less than constructing network upgrades; and (2) if, under Section 13.5, the transmission customer agrees to compensate the transmission provider for any such redispatch costs on an incremental basis as specified in the

[50] *See* Capacity Reservation Open-Access Transmission Tariffs, 61 FR 21,847 (May 10, 1996), FERC Stats. and Regs. ¶ 32,519 (1996) (Notice of Proposed Rulemaking).

[51] *See* Capacity Reservation Open-Access Transmission Tariffs, 76 FERC ¶ 61,065 (1996) (notice extending deadline for filing written comments and convening technical conference).

[52] We emphasize that transmission curtailment does not necessarily mean a power outage.

customer's service agreement prior to the commencement of service.

74. Although the existing *pro forma* tariff allows the recovery of generating unit redispatch costs, the Commission generally has not accepted proposals submitted by single-utility transmission providers to recover such costs. For instance, the Commission rejected Bangor Hydro-Electric Company's (Bangor Hydro) proposed formula to recover opportunity costs for lack of supporting data showing that its opportunity cost pricing would be consistent with the principle of comparability and because the formula lacked sufficient detail to operate as a rate formula itself.[53] The Commission directed Bangor Hydro to submit a separate section 205 filing with revised opportunity cost pricing before implementing such pricing. The Commission also rejected a proposal by the operating companies of Central and South West Corporation (CSW) regarding redispatch costs because they did not provide sufficient specificity to enable a customer to calculate or verify redispatch costs and because the formula lacked sufficient detail to operate as a formula rate.[54] The Commission also directed CSW to submit a separate filing under section 205 before implementing such pricing.

75. Because it is difficult for a single-utility transmission provider to develop a formula that specifies the costs of redispatch and protects transmission customers' interests, generation redispatch has not been used as extensively as it could be used to relieve congestion. A transmission provider will not redispatch generating units if it cannot collect its higher generation costs, and less transmission transfer capability will be available to the energy market.

76. In 1998, the Commission called on public utilities to work with the North American Electric Reliability Council (NERC) to develop a congestion management system based on redispatch.[55] NERC responded with its pilot Market Redispatch program that relied on counterflow transactions, *i.e.*, power transfers against the prevailing flows on the constraint, to relieve the congestion.[56] Although the program has been in place for several years, it has been implemented only infrequently because of the difficulty in establishing counterflow transactions and the limited availability of data to the transmitting customer.[57]

77. In 1998, Commonwealth Edison Company (ComEd) proposed a similar voluntary redispatch program, which predated NERC's Market Redispatch Program.[58] In November 1998, ComEd submitted the first of two interim reports to the Commission summarizing its experience with the program.[59] It determined that a single utility cannot effectively offer redispatch over other systems, especially where other generation owners do not participate.

78. The overall result of the Order No. 888 congestion management system is that the transmission system is not utilized in the most efficient manner. Customers can be denied access to lower-cost supplies that could be made available if the congestion management and pricing system had an efficient and fair method of recovering the cost of generator redispatch.

79. Managing congestion using an LMP system, coupled with a single transmission service that relies on price (rather than first-come, first-served) to allocate limited transmission capacity, will resolve these problems.

4. Seams Problems

80. A lack of common transmission rules inhibits competition in power markets not only when there are different rules for different customers under one public utility's tariff or one RTO's tariff, but also when there are different rules from one public utility to the next, or from one RTO to the next. The term ''seam'' has come into common use in the electric power industry over the last several years to refer to a boundary between areas with different transmission or other market rules. Market participants assert that it can be difficult to move power ''across a seam'' from one area to another.

81. Seams issues include differences in transmission rules as well as differences in power market rules. They include such diverse matters as different operating rules (*e.g.*, rules for recalling firm transmission capacity; coordination of generation and transmission maintenance schedules; how parallel path flows are determined to affect other regions); different market rules (*e.g.*, bidding rules; market product definitions); different market designs (*e.g.*, congestion management procedures; demand response rules; market price intervention practices); different business practices (*e.g.*, scheduling practices; reservation practices; OASIS designs; processes to verify transactions between ISOs and market participants; transmission and generation outage information dissemination, compensation, and coordination rules; generation interconnection practices; liability provisions); and different electronic and telephonic communications protocols.

82. Market participants have called for a ''seamless market,'' by which they mean a market whose operation is not encumbered by differences in rules at public utility or RTO boundaries. To achieve a seamless market, some assert that rules may differ but only in ways that the differences are invisible to power sellers and buyers. Others assert that such management of differences rarely works in practice and that the rules must be the same everywhere to achieve a seamless market.

83. The Commission has long recognized the need for more coordination and uniformity throughout a region in transmission matters. Our Regional Transmission Group Policy Statement of 1993[60] encouraged public utilities to develop a common set of rules for regional expansion planning, and our Transmission Pricing Policy Statement of 1994[61] encouraged the development of a common pricing policy for a region that would internalize and rationalize the pricing of parallel path flows. As explained above, Order Nos. 888 and 2000 recognized the need to bring the various public utility

[53] *See* Allegheny Power System, Inc., *et al.*, 80 FERC ¶ 61,143 (1997).

[54] Central Power and Light Company, 81 FERC ¶ 61,311 (1997).

[55] The NERC rules for protecting the system were designed to adapt the Commission's Order No. 888 individual utility transmission curtailment requirements to multi-system transactions and parallel flows. *See* North American Electric Reliability Council, 85 FERC ¶ 61,353, 62,363–64 (1998).

[56] *See* North American Electric Reliability Council, *et al.*, 87 FERC ¶ 61,160 (1999).

[57] NERC identified several problems with the program in a January 31, 2002 submittal to the Commission: (1) The Market Redispatch customer cannot easily anticipate and specify in advance which facilities will overload and require transmission curtailment; (2) the Market Redispatch transaction must provide a counterflow for the entire protected transaction even though the required transmisssion curtailment may be only a portion of the original protected transaction; and (3) the Market Redispatch customer cannot easily discover the availability of generator pairs for counterflow transactions. *See* Report on Market Redispatch Pilot Program by NERC Market Interface Committee and Motion to Continue Market Redispatch Program, Docket No. ER02–933–000, at 3 (Jan. 31, 2002).

[58] *See* Commonwealth Edison Company, *et al.*, 83 FERC ¶ 61,145 (1998).

[59] *Interim Report on Non-Firm Redispatch*, Docket No. ER98–2279–000 (Dec. 17, 1998).

[60] Policy Statement Regarding Regional Transmission Groups: Policy Statement, 58 FR 41,626 (August 5, 1993), FERC Stats. & Regs. ¶ 30,976 (Jul. 30, 1993).

[61] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 59 FR 55,031 (November 3, 1994), FERC Stats. & Regs. ¶ 31,005 (Oct. 26, 1994), *order on reconsideration and clarifying policy statement*, 71 FERC ¶ 61,195 (1995).

transmission systems in a region under a common set of transmission rules. Order No. 888 not only applied a common set of open access transmission rules to public utility transmission systems, but included a reciprocity provision that conditioned a non-public utility's use of a public utility's open access transmission tariff on the non-public utility's agreement to provide comparable transmission service to the public utility. Indeed, Order No. 888 also encouraged the formation of ISOs not only to bring all the transmission systems in a region under common rules, but also under unified operation. Many parties in Canada have stressed the necessity of having a common set of rules for reliability and trading protocols for cross-border transmission facilities.[62] Order No. 2000 built on this theme by strongly encouraging the formation of RTOs to bring all facilities in a region under a common set of transmission rules. However, RTOs have not developed at the pace anticipated when Order No. 2000 was issued and seams problems continue to exist. In June 2001, the Commission held a technical conference on seams issues.[63] Participants to the seams conference explained that resolution of seams issues is critical for making the inter-RTO transmission systems and power markets work.

84. We set forth in Appendix C a number of examples of differences in rules that can create seams problems, and a discussion of efforts at the Commission or within the industry to address seams problems.

85. The requirement under Standard Market Design for a single tariff and a single market design operating with the same set of rules throughout the entire interconnection resolves the seams problems discussed above.

5. Market Design Flaws

86. Poorly designed market rules, or market rules with unforeseen or unintended consequences, can have a debilitating effect on markets, market pricing and overall confidence in the markets of the market participants. Moreover, differences in market designs in neighboring regions can also lead to problems such as the exercise of market power through the exploitation of the differences.

87. Wholesale electricity markets are complex, with multiple products traded at multiple locations on different time-frames, while subject to the unique physical characteristics of electricity (*e.g.*, non-storable, need for system stability and balancing, physics of power flows). Market rules have been affected by the variation in generation mix, the transmission network layout and the local and regional regulatory history in different regions of the country. For example, the initial California markets had a design quite different from the designs of the markets in the Northeast region (PJM, New York and New England).

88. In the regions where voluntary, organized ISO markets for energy, transmission and ancillary services have been established under the existing tariff, problems due to the design choices have been characterized as ''market design flaws.'' A market design flaw is a market rule—including product specification, bid format, auction rules and pricing rules—that allows distortions in the market prices or availability of a product or service, whether energy, ancillary services, transmission service or installed capacity. In the years since the ISO markets have been operating, dozens of market design flaws have been identified, ranging from minor problems that cause temporary inconveniences to major problems that require markets to be re-designed. No region has been exempt from market design flaws of one type or another. We set forth in Appendix C examples of specific design flaws.

89. These problems have resulted in markets that are inefficient and do not produce the lowest reasonable prices for electric power. These problems cannot be resolved on a case-by-case basis because that will maintain and exacerbate the problems due to local differences in rules. Only standardization of electricity market design will solve these problems. In the parts of the country in which markets are most mature, including the Northeast, Midwest and California, there is broad consensus on the principal elements of market design and business practices. A standard market design rule will help advance this process and extend it to other regions. Our goal is to use the Standard Market Design rulemaking to address and remedy many of the market design flaws identified to date and to raise the quality of all electric markets simultaneously.

90. Market rules will need to be flexible and have the ability to evolve over time. However, consistent rules across the entire interconnection based on best practices, coupled with sound market monitoring to promptly identify and correct any design flaws will provide the necessary foundation for future market innovation and improvement.

C. Reform Essential Given the Changed Nature of the Electric Industry

91. The need to address the instances of discrimination described above is all the more critical given the changing nature of the electric industry. The United States electric power industry is in the middle of a transition from a predominantly monopoly industry to a predominantly competitive industry. The fundamental economic driver of change has been, and continues to be, the reduction of economies of scale in new generation construction, combined with environmental restrictions that encourage gas-fired units. This is due in large part to the introduction during the 1980s of highly efficient gas turbines and combined cycle generators that produce much more electricity from a given amount of gas. A relatively small gas-fired generator can compete effectively with power from a large central generating station. Additionally, small distributed generation is becoming economic, and some renewable energy resources, especially wind power generation, are also on the verge of becoming competitive.[64] In the right locations, wind generating units can compete with the much larger coal, nuclear and hydroelectric units.[65]

92. Because of these fundamental changes in industry technology, small producers of electricity can compete with large producers, and both the smaller utilities and the retail customers of a number of utilities have demanded access to competing power suppliers in hopes of lowering their electric bills,

[62] *See, e.g.*, Ambassador Michael Kergin (Canada) letter to Honorable Thomas A. Daschle, Senate Majority Leader, dated November 2, 2001:

Canadian electricity companies are linked to their counterparts in the U.S. through a number of major connections crossing our common border. We share a truly international electricity grid. This interconnectedness itself enhances our respective energy security, but it also places an onus on our countries to act together to manage the grid. Nowhere is that more important than in the area of electricity reliability. * * * Because uniformity in reliability standards is required to enable effective electricity trade, variations in standards would impede electricity trade and balkanize markets.

[63] *Conference on RTO Interregional Coordination*, Docket No. PL01–5–000, June 19, 2001. Called by many the ''FERC Seams Conference,'' this technical conference on the RTO interregional coordination requirements of Order No. 2000 helped the Commission learn about seams issues and about how uniform standards for some rules could benefit power markets.

[64] *See, e.g.*, International Energy Agency, Distributed Generation in Liberalized Electricity Markets, International Energy Agency (June 2002); and Ann Chambers, *et al.*, Distributed Generation: A Nontechnical Guide (PennWell Corp. 2001).

[65] *See* Christine Real de Azua, Wind Power: Poised for Take Off? A Survey of Projects and Economics, Pub. Util. Fort., Aug. 2001 at 38.

improving service and harnessing new technologies. The pressures for retail access have been greater in regions with higher rates, which are typically regions with few low-cost natural resources for generating electric power, such as nearby coal mines, gas fields, and hydroelectric areas.[66] Many of these regions have taken the lead in retail restructuring, while regions with historically low electricity production costs have proceeded more cautiously or even affirmatively decided not to change their retail access policies or to support their local utilities' participation in regional programs at this time.[67]

93. One hallmark of electric industry restructuring has been the growth of wholesale trade. In the past, wholesale power purchases made up a small fraction of a large vertically integrated utility's power supply, with most of its power needs met by its own generation. Today, however, even large vertically integrated utilities rely increasingly on wholesale purchases for their energy supplies. For example, as shown in Table 1, between 1989 and 2000, generation by investor-owned utilities grew from 2,132 thousand GWh to 2,230 thousand GWh, an increase of less than 5 percent. During this time, wholesale power purchases by these utilities almost tripled. Table 1 also shows that in 1989 wholesale power purchases provided 18 percent of the total electric energy available to investor-owned utilities from both wholesale purchases and their own generation. By 2000, wholesale purchases provided over 37 percent of investor-owned utility electric energy. This percentage has steadily increased since 1989, and is expected to continue to grow as utility-owned plants are sold or retired and new power supplies are acquired competitively in most parts of the country.

TABLE 1.—INVESTOR-OWNED UTILITIES' TOTAL PURCHASES, 1989–2000, AS A PERCENTAGE OF ENERGY PURCHASED AND SELF-GENERATED

Year	IOUs' purchases (GWh)	IOUs' generation (GWh)	Purchases (purchases + generation) (%)
1989	460,627	2,132,065	17.8
1990	530,325	2,134,429	19.9
1991	635,015	2,145,435	22.8
1992	671,758	2,143,847	23.9
1993	718,876	2,216,724	24.5
1994	732,710	2,237,652	24.7
1995	786,676	2,269,958	25.7
1996	916,087	2,308,156	28.4
1997	1,080,538	2,321,225	31.8
1998	1,073,638	2,402,571	30.9
1999	1,083,892	2,353,639	31.5
2000	1,324,558	2,229,617	37.3

Source: RDI POWERDAT Database.

Note: Data for 2001 is not yet available. Investor-owned utility purchases include purchases from affiliates.

94. Table 1 demonstrates the increasing importance of competitive wholesale energy acquisition in the United States electric power industry, and the need for this Commission to ensure that transmission, market rules and institutions are reformed as necessary to support the new environment. It also makes clear that a retreat from competitive markets to a cost-regulated vertically integrated world would be difficult—the nation now depends increasingly on wholesale interstate electricity markets.

95. Similar data are presented in Tables 2 and 3 for large public power utilities and generation and transmission cooperatives that generate at least some of their own power.[68] These tables show that wholesale purchases, on average, provide about 40 percent of the power needs of these large utilities. Data are not presented for the smaller public power and cooperative utilities because they typically do not self-generate but buy all of their power at wholesale.

TABLE 2.—LARGE PUBLIC POWER UTILITIES' TOTAL PURCHASES, 1992—2000, AS A PERCENTAGE OF ENERGY PURCHASED AND SELF-GENERATED

Year	Utilities' purchases (GWh)	Utilities' generation (GWh)	Purchases (Purchases + generation) (%)
1992	297,076	520,348	36.3
1993	314,472	549,810	36.4
1994	331,643	555,198	37.4
1995	332,962	586,737	36.2
1996	350,880	645,740	35.2

[66] *See* Energy Information Administration, The Changing Structure of the Electric Power Industry 2000: An Update, at 81–82 (2000), *available in* http://www.eia.doe.gov/cneaf/electricity/*chg_stru_update/update2000.pdf*> (hereinafter Electric Power Industry 2000 Update).

[67] *See id.*

[68] Note that the data available for large public power and cooperative utilities is not complete but represents a sampling of these utilities. The sample size typically grew each year so that an apparent growth in the wholesale purchase percentages could reflect the addition of smaller utilities that purchase more power at wholesale.

TABLE 2.—LARGE PUBLIC POWER UTILITIES' TOTAL PURCHASES, 1992—2000, AS A PERCENTAGE OF ENERGY PURCHASED AND SELF-GENERATED—Continued

Year	Utilities' purchases (GWh)	Utilities' generation (GWh)	Purchases (Purchases + generation) (%)
1997	349,641	674,725	34.1
1998	364,434	676,698	35.0
1999	394,617	634,548	38.3
2000	429,369	631,143	40.5

Source: RDI POWERDAT Database.

''Large Public Power Utilities'' includes municipals, federal power authorities. Data for 2001 is not yet available.

TABLE 3.—GENERATION & TRANSMISSION COOPERATIVES' TOTAL PURCHASES, 1992—2000 AS A PERCENTAGE OF ENERGY PURCHASED AND SELF-GENERATED

Year	Cooperatives' purchases (GWh)	Cooperatives' generation (GWh)	Purchases (Purchases + generation) (%)
1992	85,226	136,417	38.5
1993	93,756	149,783	38.5
1994	96,148	156,589	38.0
1995	99,909	166,099	37.6
1996	117,455	172,161	40.6
1997	112,822	176,689	39.0
1998	115,003	177,534	39.3
1999	122,151	172,323	41.5
2000	127,785	171,198	42.7

Source: RDI POWERDAT Database.

Note: ''Generation & Transmission Cooperatives'' includes cooperatives with generation and transmission facilities, but excludes distribution cooperatives. Data for 2001 is not available yet.

96. The transition to competitive electricity markets is characterized by opportunity and uncertainty. The promise of competition is the opportunity to develop more innovative technologies, improve services, lower average electric rates and provide more customer choice than is likely under a strictly regulated monopoly environment. During the transition to competition, these promises are only partly fulfilled, and results vary regionally as a result of different choices about retail restructuring. Additionally, the California electricity crisis of 2000–2001, allegations of improper trading practices, the collapse of Enron Corporation in December 2001 and the deteriorating financial health of many electric suppliers and marketers at this time have added unprecedented uncertainty about, and lack of confidence in, today's electric markets.

97. In addition to general concerns about adequate constraints on the exercise of market power by power sellers, there is uncertainty in the industry about impediments to new generators entering the market, adequacy of incentives to build much needed generation and transmission infrastructure, availability of non-discriminatory transmission service for all sellers and buyers in a regional market and the risk of making long-term commitments when market rules are subject to frequent experiment and change. Differences in market rules between regions make it difficult to transact business across regions and thus also lead to increased uncertainty in the industry and the risk of market manipulation.

98. Investors, generators and transmission providers are reluctant to invest in new generation and transmission infrastructure if the rules for setting energy or transmission prices are not yet known or are subject to frequent revision.[69] Thus, uncertainty about the direction of competition policies inhibits the development of the very infrastructure needed both to allow competition to work and to assure reliability in a competitive environment. Customers are reluctant to sign contracts for power or to change suppliers if long-term power markets are unnecessarily volatile and they cannot obtain price certainty.

99. The promise of wholesale competition may go unfulfilled—or at best continue to be delayed at great cost—unless many of these uncertainties are resolved. This proposed rule is intended to help resolve generically many of the uncertainties facing the electric power industry and to restore confidence in future power markets.

D. Legal Authority and Findings

100. The primary purposes of the Federal Power Act are to curb abusive practices by public utilities and to protect customers from excessive rates and charges. To achieve these ends, section 205 of the Federal Power Act requires that no public utility shall ''make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage,'' with respect to the transmission of electric energy in interstate commerce or wholesale sales.[70] Section 206 of the Federal Power Act authorizes the Commission

[69] *See generally* U.S. Department of Energy, National Transmission Grid Study (May 2002), *available in* <*http://tis.eh.doe.gov/ntgs/*> (hereinafter DOE National Transmission Grid Study).

[70] 16 U.S.C. 824d.

to investigate and remedy unduly discriminatory or preferential rules, regulations, practices or contracts affecting public utility rates for transmission in interstate commerce and for sales for resale of electric energy in interstate commerce.[71] It also authorizes the Commission to investigate and remedy unjust and unreasonable rates, charges or classifications, and any rules, regulations, practices or contracts affecting such rates, charges or classifications.

101. Moreover, the Commission's regulatory authority ''clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to [Federal Power Act sections] 202 and 203, and under like directives contained in [Federal Power Act sections] 205, 206, and 207.'' [72] The Commission's authority to remedy undue discrimination and anticompetitive effects is broad.[73]

102. The Court of Appeals for the District of Columbia Circuit reviewed challenges to Order No. 888 and found that the ''open access requirement is authorized by and consistent with the [Federal Power Act],'' and upheld the order.[74] On appeal, the Supreme Court affirmed the Commission in applying its open access requirements to transmission used for wholesale and unbundled retail sales of electric energy in interstate commerce, but also concluded that the Commission had jurisdiction over transmission used for bundled retail sales of electric energy in interstate commerce. The Supreme Court further stated that the Commission may regulate bundled retail transmission of energy as a means of addressing undue discrimination. While the Court did not adopt the appellants' suggestions that the Commission's finding of discrimination in the wholesale electricity market suggested the presence of discrimination in the retail electricity markets,[75] it stated that ''[w]ere FERC to investigate this alleged discrimination and make findings concerning undue discrimination in the retail electricity market, § 206 of the FPA would require FERC to provide a remedy for that discrimination * * * And such a remedy could very well involve FERC's decision to regulate bundled retail transmissions'' of energy.[76]

103. We find that undue discrimination and anticompetitive behavior persist, as detailed in Section III and Appendix C, in both wholesale and retail transmission of energy. Pursuant to our statutory mandate to remedy undue discrimination and anticompetitive effects in these markets, as interpreted by the Supreme Court, we will apply the requirements of this rule to the transmission component of bundled retail transactions. At a minimum, all transmission service in interstate commerce must be subject to the same non-discriminatory non-rate terms and conditions in order to eliminate undue discrimination in wholesale markets and in retail choice markets. With respect to rates for bundled retail transmission service, however, we will work with states to address difficult transition rate issues.

104. In light of these statutory responsibilities and authorities under the Federal Power Act, we have assessed the state of the electric utility industry and determined that it is necessary to act promptly to provide stability to the industry and to assure that customers receive adequate supplies of electric energy at the lowest reasonable price. During the past six years, the implementation of open access transmission under Order No. 888 has fundamentally altered the landscape of the electric utility industry by removing major discriminatory barriers to the use of the interstate transmission grid and thereby opening the door to competition in wholesale electric power markets. However, even with the Order No. 888 open access *pro forma* transmission tariff and Order No. 889 transmission standards of conduct in place, there continues to be undue discrimination in the provision of interstate services. Experience under the *pro forma* tariff has demonstrated that unduly discriminatory transmission practices continue today. Further, existing trading rules and design of wholesale power markets do not consistently prevent market manipulation or send proper price signals to participants or allocate scarce resources to those who value them most and thus could result in unjust and unreasonable rates. Thus, competition either does not exist in many areas of the country or competition is distorted.

105. We find that:

(1) the operation of the Commission's *pro forma* transmission tariff (which is administered by vertically integrated as well as non-vertically integrated public utilities such as ISOs) contains provisions that, in practice, permit undue discrimination in the provision of transmission services;

(2) public utilities that own, operate or control transmission facilities and also participate in power markets continue to possess substantial transmission market power and retain the ability to unduly discriminate in the provision of transmission service and spot market energy services;

(3) lack of standardized wholesale electric market design allows undue discrimination within and across regions, can result in unjust and unreasonable pricing and allocation of transmission and permits the exercise of market power (and thus unjust and unreasonable rates) in power markets; and

(4) proper price signals are not being sent to the marketplace, with the result that market-based rates in many places are distorted, and reasonably accurate price signals necessary for infrastructure additions are not being sent.

106. To remedy remaining undue discrimination in the provision of interstate transmission services and in other industry practices, and to ensure just and reasonable rates for sales of electric energy within and among regional power markets, the Commission proposes to modify the Order No. 888 *pro forma* tariff to reflect non-discriminatory, standardized transmission service and require standardized wholesale electric market design. The Commission also proposes to expressly exercise jurisdiction over all transmission in interstate commerce by public utilities.

IV. The Proposed Remedy

107. The Commission's goal in Order Nos. 888 and 2000 was to harness the benefits of competition for the nation's electricity customers by assuring adequate and reliable supplies of electricity at a just and reasonable price. As discussed above in the Need for Reform section (Section III), the current rules and regulations have prevented the full attainment of that objective. To address these problems in the current system, we are proposing a comprehensive package of reforms that are described more fully in this section.

108. Section III and Appendix C provide numerous examples of ways that an entity that owns both

[71] 16 U.S.C. 824e.

[72] *See* Order No. 888 at 31,669 (quoting *Gulf States Utilities Co.* v. *FPC,* 411 U.S. 747, 758–59, *reh'g denied,* 412 U.S. 944 (1973)). *See also City of Huntingburg* v. *FPC,* 498 F.2d 778, 783–84 (D.C. Cir. 1974) (finding that the Commission has a duty to consider the potential anticompetitive effects of a proposed interconnection agreement).

[73] *See* Order No. 888 at 31,669 (the Federal Power Act fairly bristles with concern for undue discrimination (citing *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 998 (D.C. Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988))).

[74] *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d at 685.

[75] *See id.* at 1028.

[76] *Id.*

transmission and generation can discriminate in favor of its own customers or generation under the current tariff. The problem stems from the differences in the sets of rules that apply to users of the transmission system. First, the current regulatory system allows vertically integrated utilities to discriminate in favor of their bundled retail load at the expense of wholesale customers. This occurs because transmission service for bundled retail customers is subject to different rules and rates than service for wholesale customers. Second, the current distinction between Point-to-Point Transmission Service and Network Integration Transmission Service also creates opportunities for undue discrimination in favor of generation owned by the transmission owner or an affiliate.

109. To remedy this discrimination we propose to place all transmission customers under the same set of rules. We propose to place transmission service for bundled retail customers under the same terms and conditions of service as wholesale transmission service. To accomplish this we propose to revise the existing *pro forma* tariff to remove provisions that grant preferential treatment to transmission service for bundled retail customers. We propose that all public utilities that own, control or operate interstate transmission file these interim changes no later than July 31, 2003. We also propose that no later than September 30, 2004, or such date as the Commission may establish, only Independent Transmission Providers would operate Commission-jurisdictional facilities. This requirement will apply whether or not the public utility that owns, controls or operates interstate transmission facilities has joined an RTO.[77] We are proposing specific governance requirements that must be met by the Independent Transmission Provider.

110. Also, no later than September 30, 2004, or such date as the Commission may establish, we propose to eliminate the distinction between Point-to-Point and Network Integration Transmission Services by having one service, Network Access Service, that contains elements of both types of service—the flexibility of Network Integration Transmission Service and the tradability of Point-to-Point Transmission Service. We propose these time periods to provide sufficient time for the development of the necessary new software systems. Network Access Service is based on an open spot market for imbalance energy and a uniform congestion management methodology, *i.e.*, LMP, to more efficiently manage the transmission grid. The spot energy market and LMP rely on management of the transmission system and bidding by supply and demand resources attached to the transmission grid under market rules and protocols.

111. To provide the price signals needed to manage congestion, the Independent Transmission Provider will be required to operate a day-ahead and real-time market for energy. To provide customers with a mechanism for achieving price certainty under the new congestion management system, we also propose to require that customers be given Congestion Revenue Rights for their historical uses that protect against congestion costs when specific receipt and delivery points are used.

112. LMP and Congestion Revenue Rights will provide price signals to indicate where new investment is needed; however, the price signals alone may not guarantee sufficient investment. We also propose to require a regional transmission planning and expansion process to provide a backstop process for ensuring that needed transmission construction is undertaken. We propose that this process begin six months from the effective date of the Final Rule, even though much of the country will not have had the opportunity to respond to LMP and Congestion Revenue Rights for another few years.

113. At this stage of the industry's evolution, structural barriers to competitive markets remain, so to address this we are proposing market power mitigation measures for the spot markets that will be operated by the Independent Transmission Provider. These measures are designed to address the two significant structural problems in wholesale energy markets—the existence of localized market power that arises from transmission constraints, and the lack of price-responsive demand. The market power mitigation proposal is a framework that can be tailored to reflect the competitive conditions of the particular region. It is designed to be reexamined annually and adjusted as needed to reflect changes in the competitive structure of the region, including a phasing out of mitigation measures as resource adequacy and demand response develops. Because market power mitigation of spot market prices will tend to suppress the price signals for new entry, we are also proposing a non-price mechanism to assure that load meets a long-term resource adequacy requirement.

114. To avoid the market design flaws discussed in the Need for Reform section (Section III) and Appendix C and market manipulation in Appendix E, and to minimize the potential for seams issues, we propose a standardized tariff that incorporates the best practices and builds on the lessons from our experience with organized markets. In Appendix B, the proposed SMD Tariff standardizes many aspects of the basic market design. However, it also allows flexibility in a number of areas to customize the basic market design to meet regional requirements where such customization will not lead to further discrimination or inefficiencies.

115. We propose to permit small entities to seek waiver of the Standard Market Design Final Rule requirements. The regulations we propose include waiver provisions under which public utilities, and non-public utilities seeking exemption from the reciprocity condition, may file requests for waivers from all or part of the Commission's regulations.

116. Finally, while we have attempted to standardize the basic aspects of the market design policy, this proposed rule does not include detailed business practices and communication protocols that will be needed to administer Standard Market Design. We fully appreciate the benefits of business practice standardization and, as we did in the natural gas industry, we believe it is best if industry participants develop these types of highly detailed and technical standards. Thus, we are proposing a process, similar to that used in the natural gas industry, that could be used for standardization of business practices, data sets and communication protocols that includes representation of all affected market participants. Upon its formation, the Wholesale Electric Quadrant of the North American Energy Standards Board (NAESB), working closely with Independent Transmission Providers who would collectively serve in an advisory capacity to the board, would produce business practice and electronic communication standards. NAESB would notify the Commission when it has adopted standards, and the Commission would then use rulemaking proceedings to propose the incorporation of these standards by reference into the Commission's regulations. If the industry is unable to reach consensus on a particular standard, the Commission would be available to resolve the dispute, so that the industry process can continue, or the Commission could develop its own standards if necessary. Consistent with gas industry regulation, issues of policy that affect significant resources or that

[77] A Commission-approved RTO would meet the requirements of an Independent Transmission Provider.

may cause cost-shifting would be resolved at the Commission rather than through the standard setting body.

A. The Interim Tariff

117. Standard Market Design is intended to cure undue discrimination, in part, with respect to the use of the transmission grid. As we discussed in Section III.B.2, there are different rules for bundled retail transmission service and for wholesale and unbundled retail transmission services. These differences result in unduly discriminatory preferences for the vertically integrated transmission owner's bundled retail customers.

1. Placing Bundled Retail Customers Under the Interim Tariff

118. We propose that to eliminate this undue discrimination, the transmission component of bundled retail service must be taken under an open access transmission tariff. Under the current *pro forma* tariff, a vertically integrated utility is required to designate the resources it uses to serve bundled retail customers in the same manner as wholesale customers are required to designate network resources under the Network Integration Transmission Service. We propose to use these designations of network resources in converting service used to meet retail obligations. The existing level of service would be provided pursuant to the new Network Access Service. The load-serving entity or the retail customer would receive either Congestion Revenue Rights or the auction revenues for these rights for the currently designated resources. In Section V of this Notice of Proposed Rulemaking, the Commission sets forth a proposed time-line and implementation process for this conversion process.

119. In the interim, however, we propose to require that bundled retail load be placed under the existing *pro forma* tariff. While many of the revisions required by Standard Market Design are dependent on the production and adoption of software to determine locational marginal prices and to operate markets, placing bundled retail load under the existing *pro forma* tariff can be done immediately. This will remove certain discriminatory practices and is the first step towards placing all transmission service under one tariff. This will require several revisions to the existing *pro forma* tariff to modify provisions that define the different treatment granted to the service of bundled retail load. Among the revisions that the Commission proposes to require public utilities to file are revisions to Sections 1.19, 13.5, 13.6, 14.2, 22.1(a), 22.1(a), 28.2, 28.3, 33.2, 33.3, 33.3 and 33.5. The specific changes are identified in Appendix A.

120. We propose that the public utilities file these revisions to their tariffs and execute service agreements to take Network Integration Transmission Service on behalf of their bundled retail load no later than July 31, 2003. We recognize, however, that some public utilities (*e.g.*, ISOs) may already be serving bundled retail load under the *pro forma* tariff. Accordingly, to the extent that a public utility can demonstrate that it complies with this requirement, it may so indicate in its compliance filing.

2. Additional Interim Revisions to the *Pro Forma* Tariff

121. Since the implementation of the existing *pro forma* tariff, the Commission has offered clarifications to various provisions of the tariff. Perhaps the most important of these dealt with a customer's right to roll over its existing contract for long-term firm service (Section 2, Initial Allocation and Renewal Procedures).

122. In several orders, the Commission clarified three significant points: (1) A customer must submit a request to roll over its contract no later than sixty days prior to the date the current service agreement expires;[78] (2) the public utility may only deny a customer its right to roll over a contract due to future load growth if the public utility includes in the original service agreement a specific, reasonably forecasted need for the transfer capability to serve load growth for network customers at the end of the term of the service agreement;[79] and (3) a long-term firm customer that requests to use alternate point(s) of receipt or delivery retains its right of first refusal for service at the original point(s) of receipt and delivery at the time the current service agreement expires.[80]

123. These revisions have a significant impact on the rights of current transmission customers and will continue to do so up until the time the SMD Tariff, including auctions of Congestion Revenue Rights, is in place.[81] We propose to require public utilities to make the tariff changes to Section 2.2 of the existing *pro forma* tariff, as outlined in Appendix A.

B. Independent Transmission and Markets

124. Another form of undue discrimination is the lack of independence of the transmission provider in many regions of the country. As discussed in Section III.B.1, remaining corporate ties between generation and transmission within public utilities are problematic since they allow the vertically integrated utility to exercise market power to advantage its affiliated generation.

1. Independent Transmission Providers

125. To remedy this undue discrimination, transmission service must be provided by an independent entity. Therefore, we propose to require all public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to: (1) Meet the definition of Independent Transmission Provider, (2) turn over the operation of its transmission facilities to an RTO that meets the definition of Independent Transmission Provider, or (3) contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

126. An Independent Transmission Provider is any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the SMD Tariff, and that is independent (*i.e.*, has no financial interest, either directly or through an affiliate, in any market participant in the region in which it provides transmission services or in neighboring regions).

127. We propose that affected public utilities must inform the Commission which Independent Transmission Provider will operate the public utility's transmission facilities no later than July 31, 2003. However, a public utility that is a member of an approved RTO or ISO or other entity that meets the definition of Independent Transmission Provider may file a request for a waiver of the filing requirements of this paragraph on the ground that it has already complied with the requirement.

[78] *Entergy Power Marketing Corporation* v. *Southwest Power Pool,* 91 FERC ¶61,276 (2000).

[79] Order No. 888–A, as clarified by Public Service Company of New Mexico, 85 FERC at 62,006 (1998); *Public Service Company of New Mexico* v. *Arizona Public Service Company,* 99 FERC ¶61,162 (2002); *Exelon Generation Company, LLC* v. *Southwest Power Pool,* 99 FERC ¶ 61,235 (2002).

[80] Commonwealth Edison Company, 95 FERC ¶ 61,027 (2000).

[81] The protections offered by rollover rights are of value in a first-come, first-served priority system, and are valuable for a direct allocation of Congestion Revenue Rights. Once Congestion Revenue Rights are fully auctioned, and access to transmission service will be based on a willingness to pay congestion costs (and losses), it may no longer be necessary.

128. Any entity meeting the definition of Independent Transmission Provider would file the SMD Tariff to provide transmission services, including ancillary services, and to administer the day-ahead and real-time energy and ancillary services markets. As discussed further below, an Independent Transmission Provider would also perform market monitoring and market power mitigation, long-term resource adequacy and transmission planning and expansion on a regional basis.

129. An Independent Transmission Provider would also file under section 205 any changes to transmission rates necessary to implement Standard Market Design, no later than 60 days prior to the date on which it proposes to implement Standard Market Design.

130. In addition, one or more public utilities may jointly file an application to meet the requirements of Standard Market Design. Also, an Independent Transmission Provider may make necessary filings on behalf of public utilities required to meet the requirements of this paragraph.

131. We seek comment on whether this remedy is adequate to remove the potential for unduly discriminatory behavior on the part of a vertically integrated transmission provider. Can the requirements of Standard Market Design be satisfied either by performing the function through an RTO or contracting with an independent entity to perform them? Given that most transmission providers have filed proposals to join an RTO, is a non-RTO compliance option necessary to cure undue discrimination and produce just and reasonable rates for transmission service and the sale of electric energy?

2. Role of Independent Transmission Companies in Standard Market Design

132. We have long recognized that the Independent Transmission Company (ITC) business model can bring significant benefits to the industry. Their for-profit nature with a focus on the transmission business is ideally suited to bring about: (1) Improved asset management including increased investment; (2) improved access to capital markets given a more focused business model than that of vertically integrated utilities; (3) development of innovative services; and (4) additional independence from market participants. We believe that these characteristics of ITCs can have significant benefits for the implementation of Standard Market Design, particularly in the areas of development of transmission infrastructure and structural independence from market participants.

133. The Commission recently approved a proposal by several transmission owners to form an ITC, TRANSLink Transmission Company, LLC (TRANSLink), to share responsibility with the Midwest ISO Regional Transmission Organization (the Midwest ISO) [82] and other regions for the RTO functions prescribed in Order No. 2000. In that proceeding, the Commission approved a hybrid RTO formation under which specific RTO functions were delegated to either the RTO or the ITC. Regarding the delegation of functions we stated:

> Our rulings on the allocation of functions issues are based on our belief that for effective RTO operations, regional trading, and one-stop shopping, a single transmission provider must have overall authority and ultimate responsibility for transmission service in the region. We further believe that the security-constrained, economic dispatch needed for an efficient and reliable market is best operated by an independent regional transmission provider. However, we believe that it is acceptable for some functions with predominantly local characteristics to be delegated to an ITC so long as the RTO has oversight authority in the event that local actions have a regional impact. We find that this is critical to successful RTO development and especially important given the characteristics of the interstate transmission grid. It has become increasingly evident in recent years that even seemingly local issues, such as generator location or isolated transmission bottlenecks, can and do impact the larger grid, and that is why we believe that centralized RTO oversight is needed.
>
> We also remain concerned that vesting control into sub-regional entities may create seams which could easily lead to re-balkanization. These difficult delegation decisions are made with our firm belief that ITCs can flourish under the RTO umbrella and that in performing certain delegated functions, ITCs will be able to effectively manage their assets, protect their value, and bring their expertise to increase efficiencies and enhance the value of their business. Nevertheless, these delegation decisions should not prevent ITCs from seeking additional authority, subject to Commission approval, at a later date after ITCs have gained experience under RTO operations.[83] We are also guided by the premise that any delegation of functions to an ITC must be consistent with and further the Commission's goals in the SMD Proceeding. We assume in this order that the Midwest ISO will be the transmission provider in the TRANSLink area and will operate a real-time and day-ahead market, or any functions that are required under the SMD final rule.[84]

134. We seek comment on the functions that an ITC should perform under Standard Market Design. Should the Commission retain the same delegation of functions that was approved in *TRANSLink?* Are there elements of the proposed Standard Market Design that would justify a different delegation of functions? Should an ITC qualify as an Independent Transmission Provider?

135. We seek comment on whether an ITC that has no ties to a Market Participant, as defined in this proposal, is sufficiently independent to act as the Independent Transmission Provider. The ITC may hold grid assets such as transmission facilities and Congestion Revenue Rights and may be allowed a performance-based ratemaking program. Thus the Commission is concerned that the ITC may unduly discriminate in favor of its own transmission interests when carrying out operational and planning decisions in its role as Independent Transmission Provider. We seek comment on whether such ITC interests in transmission investment may cause the ITC to unduly discriminate in day ahead or real time markets operations or to discount generation, demand response, and other transmission owners' (*e.g.*, merchant transmission) solutions to grid problems. On the other hand, generation and demand response solutions are likely to have the first opportunity to respond to LMPs if it makes economic sense to do so, given the difficulty in siting transmission. Given the planning process and stakeholder input, as well as the Commission's authority to set rates, we seek comment on what specific ways an ITC could make such unduly discriminatory decisions? The Commission is convinced that, if its role is appropriately defined, and opportunities for undue discrimination are addressed, the ITC shows great promise to address grid problems through profit driven activities. One such activity could be reducing congestion where an ITC with properly structured performance based rates would have an incentive. What is the appropriate role for the ITC?

C. The New Transmission Service

136. To address the discrimination described in Section III above and in Appendix C, we will require Independent Transmission Providers to provide a nondiscriminatory, standard transmission service to all customers.

[82] TRANSLink Transmission Company, L.L.C., *et al.,* 99 FERC ¶ 61,106 (2002).

[83] We recognize that as the Midwest ISO and ITCs gain experience, they should, from time to time, reassess the assignment of the functions and reevaluate whether some that have been delegated to a local level need to be performed at a regional level and vice versa. Likewise, after SMD is implemented, the assignment of functions may need to be reassessed. (Footnote 37 in original).

[84] TRANSLink, 99 FERC at 61,463.

This new service, Network Access Service, combines features of both the existing open access transmission services—Network Integration Transmission Service and Point-to-Point Transmission Service. The Network Access Service is grounded in the flexibility of network integration transmission service, but adds a measure of reassignability similar to that available under firm Point-to-Point Transmission Service. Thus, Network Access Service will give all customers the opportunity to have tradable Congestion Revenue Rights [85] that will expand their transmission options and enhance competition in wholesale electric markets. It also will result in all transmission services being performed under a single set of rules.

137. To complement Network Access Service and implement the Standard Market Design, Independent Transmission Providers will manage congestion using LMP. Management of transmission grid congestion is difficult to do through bilateral transactions alone; thus a spot market is required to manage congestion efficiently. We believe that congestion management, balancing of load and generation in real time, and the provision of ancillary services can be accomplished most reliably and efficiently by a bid-based, security-constrained spot market.

138. In addition to administering a spot market to manage congestion, the Independent Transmission Provider will also use it to handle imbalances and the procurement of ancillary services. The Independent Transmission Provider would operate markets for energy, regulation, operating reserve—spinning and operating reserve—supplemental. These markets would be security-constrained, bid-based markets operated in two time frames: (1) A day ahead of real-time operations, and (2) in real time. Transmission services will be scheduled through the day-ahead and real-time markets. The Independent Transmission Provider would establish schedules for transmission service, and sales and purchases of energy, regulation, and both operating reserves, to ensure the most efficient use of the transmission grid. Although the Independent Transmission Provider will not be required to operate an organized market for either short- or long-term bilateral transactions, its scheduling process must accommodate such bilateral trades.

1. Basic Rights

139. Network Access Service builds upon the existing Order No. 888 Network Integration Transmission Service and will be available to all eligible customers. As with Network Integration Transmission Service, Network Access Service offers flexible use of the transmission grid—it allows the load-serving entity to choose to serve its load with any available resource on the system (or access any interface to import power from a neighboring system), consistent with the Network Resource Interconnection Service discussed in the Generator Interconnection proposed rule.[86] Network Access Service allows a customer to have the Independent Transmission Provider integrate, dispatch and regulate the customer's current and planned resources to serve its load as is currently done under the *pro forma* tariff. Customers, including generators and marketers, can also use this service for through-and-out service, to aggregate resources for resale, and to perform hub-to-hub transactions similar to Point-to-Point Transmission Service. In addition, Network Access Service allows the customer (1) to trade (reassign) its Congestion Revenue Rights and (2) to access points, which, under the current *pro forma* tariff, are secondary points that may be fully subscribed, by paying all applicable congestion charges.

140. Network Access Service is premised on dispatching of the regional transmission grid so that the customers that value transmission service the most will get it. All requested transactions must be physically feasible under a security-constrained dispatch. Where there are transmission constraints, the LMP system we propose will price out all transactions and redispatch available generation as needed to accommodate all requests for service.[87]

141. Network Access Service gives the customer the right to transmit power between any number of combinations of receipt and delivery points. A receipt point is defined here as the location where a transaction originates, and a delivery point is defined as the location where a transaction terminates. Receipt and delivery points include both individual nodes as well as aggregated points, *e.g.*, trading hubs. Thus, a Network Access Service customer could use this service to move power from a generator (receipt point) to a load (delivery point), from a generator (receipt point) to a trading hub (delivery point), from one trading hub to another, or from a trading hub (receipt point) to a load (delivery point). A Network Access Service customer would have access to all receipt and delivery points on the system and would be able to substitute receipt points on a daily or hourly basis through the day-ahead and real-time scheduling processes.

142. Any customer using transmission service, whether a load-serving entity, generator, or marketer, would take Network Access Service. However, as explained more fully in Section IV.D.1, only those customers taking power off of the grid would pay the access charge. (All customers would pay congestion costs and losses associated with their particular transaction.) We expect that, in most instances, it would be a load-serving entity, rather than a generator or marketer, that would be the customer for transactions that result in power leaving the grid, and thus, the load-serving entity would be the entity paying the access charge.[88]

2. Access to Transmission Service

143. Under the existing *pro forma* tariff, ''firm'' transmission service implies certainty both with respect to delivery and price. Once a customer taking firm service under the existing *pro forma* tariff agrees to pay the transmission rate and schedules service, it has full assurance that it will be able to transmit power between its chosen receipt and delivery points without service interruption (absent force majeure or curtailment) and without being subject to any additional costs (*e.g.*, redispatch). However, there are times when a transmission provider cannot offer a guarantee of service availability (absent the long-term solution of a customer agreeing to pay for system expansion). At these times, under the existing pro forma tariff, only non-firm transmission service (which can be interrupted for economic reasons)[89] is available at the stated maximum rate. Thus, the existing *pro forma* transmission service begins with the basic premise of price certainty, but includes a measure of uncertainty

[85] Congestion Revenue Rights entitle the holder to receive specified congestion revenues in the day-ahead market. To the extent that a customer's real-time schedule coincides with its day-ahead schedule and its Congestion Revenue Rights, these rights offer complete protection against uncertain congestion charges.

[86] Standardization of Generator Interconnection Agreements and Procedures, FERC Stats. & Regs. ¶ 32,560. Network Resource Interconnection Service requires that sufficient network upgrades be built so that interconnecting generators can serve load as a Network Resource, as defined by the existing *pro forma* tariff.

[87] In all but limited cases, this should allow the Independent Transmission Provider to satisfy all requests for service by customers willing to pay the applicable congestion charges.

[88] An end-use customer in a state with retail access could be the entity taking transmission service and paying the access charge.

[89] All services, including firm service, can be curtailed for reliability reasons.

regarding service availability that is resolved only if firm service can be secured. In sum, the customer is generally assured of the rate it will pay for transmission service, but, unless it has secured firm transmission service between the specified points, is not necessarily assured that it will receive transmission service.

144. With Network Access Service, all customers who want physically feasible service will be able to receive service; however, uncertainty can arise as to the rate paid to receive the service. In addition to the access charge (which recovers the embedded costs of the transmission system), the customer would be subject to the cost of congestion between its chosen receipt and delivery points. To achieve certainty with respect to price and avoid congestion costs, the customer would have to acquire the Congestion Revenue Rights associated with its specific receipt point-delivery point combination(s).[90] Thus, Network Access Service, coupled with Congestion Revenue Rights for the desired points, provides the customer with certainty with respect to delivery and price, comparable to the existing *pro forma* tariff's firm service.

145. Accordingly, customers desiring service comparable to (but actually more dependable than) existing firm transmission service would need to acquire Congestion Revenue Rights for their receipt and delivery points and schedule service between those points in the day-ahead market. With the allocation process we propose in Section IV.H.2, customers under existing contracts will receive Congestion Revenue Rights that match their current use of the system, which will ease and simplify the conversion process. Customers using non-firm transmission service under the existing pro forma tariff could request service when needed in the day-ahead or real-time markets. To the extent the customer is willing to pay congestion costs and transmission losses, its requested transmission service would be available and provided.[91] A customer also has the option of placing a limit on the amount of congestion charges it is willing to pay—to the extent that amount is exceeded, the customer would not take transmission service for that receipt point-delivery point combination during the requested time period. This means no separate non-firm transmission service option is needed under Network Access Service.

3. Service Limitations in the Existing *Pro Forma* Tariff

146. The existing *pro forma* tariff limits how the Network Integration Transmission Service and Point-to-Point Transmission Service can be used. It limits the use of interface capability by Network Integration Transmission Service customers to the amount of the customer's load. Under the LMP system that we are proposing, transmission service would be available to any customer up to the full amount of the transfer capability, so long as the customer is willing to pay the applicable congestion charges. The specifics of scheduling power across interfaces is discussed in a later section.

147. The existing *pro forma* tariff also requires the network customer to take Point-to-Point Transmission Service for any additional third-party sales transaction or to serve load on another transmission provider's system. This will no longer be necessary with Network Access Service, which will be used for all transmission services, including third-party sales transactions and transmission service for load on another transmission provider's system. A customer, however, may prefer to have separate service agreements for service to particular loads for accounting or tracking purposes.

4. Conditions for Receiving Service

148. To receive Network Access Service, a customer must meet the same requirements as those under the existing *pro forma* tariff for acquiring the right to schedule transmission service: all customers must meet creditworthiness and other eligibility standards, complete an application for service, and meet certain operating standards (*e.g.*, reliability maintenance of customer-owned facilities for integration with the transmission provider's system, including metering and communications equipment) as defined in the current *pro forma* tariff. Similarly, the customer must have a service agreement to take service under the tariff. A load-serving entity would also need a network operating agreement, which would detail how the Independent Transmission Provider's system under the SMD Tariff and the load-serving entity's system would work together (similar to a generator interconnection agreement).[92] These standards are largely unchanged from the existing *pro forma* tariff. In addition, the customer must agree to pay any congestion charges and transmission losses associated with its request[93] and any customer serving load located within the Independent Transmission Provider's system must agree to pay the applicable access charge.

5. Scheduling Transmission Service and Acquiring Congestion Revenue Rights

149. As noted above, a customer would acquire Congestion Revenue Rights to assure price and delivery certainty for its transactions. Anyone can hold Congestion Revenue Rights. Congestion Revenue Rights can be acquired through a variety of means, including: (1) Direct allocation that is based on some measure of current or historical rights to the system; (2) periodic auctions; or (3) some combination of these methods. The initial process for acquiring these rights is discussed in Section IV.H.2.

150. Transmission service will be scheduled through the day-ahead market with deviations accounted for in the real-time market, as discussed in later sections. These scheduling opportunities are comparable to the existing *pro forma* tariff's requirements (*e.g.*, firm point-to-point transmission service scheduled by no later than 10 a.m. the day before, with schedules submitted after that time accommodated, if practicable, and allowance to make changes to that ''day-ahead'' schedule prior to the start of the next clock hour). However, the new service synchronizes the scheduling of transmission service and energy, and relies on a transmission customer holding Congestion Revenue Rights or its willingness to pay the cost of congestion, rather than on a firm/non-firm, first-come, first served method, to ration capacity.

151. A Network Access Service customer would have to indicate the location of its receipt and delivery points when it schedules service in the day-ahead or real-time markets.[94] If a

[90] Congestion Revenue Rights provide the rights holder with the revenues associated with congestion between the associated points; thus, any congestion costs it pays are fully offset by these revenues. To the extent the Congestion Revenue Rights holder opts not to schedule transmission service at those points, it would still receive the congestion revenues.

[91] As discussed in Section IV.D.3, customers exporting power from or transmitting through one region would not be subject to that region's access charge, but would be liable for the cost of congestion and transmission losses associated with its transaction.

[92] Consistent with the existing *pro forma* tariff, a Network Access Service customer would retain the right to request that the Independent Transmission Provider file an unexecuted transmission agreement or network operating agreement if the two parties cannot agree on the terms and conditions of service.

[93] As noted earlier and more fully explained in Section IV.E.3., a customer can protect itself against the costs of congestion by acquiring Congestion Revenue Rights in the amount of its load and between the receipt/delivery points where its desired resources and loads are located.

[94] Further, consistent with the existing *pro forma* tariff and the Commission's decision regarding ''tagging,'' the customer must identify the ultimate source and sink so that the various system operators in an interconnection can assess the simultaneous feasibility of all scheduled power flows. *See* Coalition Against Private Tariffs, 83 FERC ¶ 61,015 at 61,040, *reh'g denied,* 84 FERC ¶ 61,050 (1998).

customer holds Congestion Revenue Rights between a set of receipt and delivery points in the day-ahead market, but later decides to take transmission service between a different set of points, the customer would no longer have full protection against congestion costs for its transaction in the day-ahead market and could incur different congestion costs than the congestion revenues associated with the Congestion Revenue Rights it holds. Similarly, to the extent that a customer's real-time transactions differ from its day-ahead schedule, the customer would be liable for any redispatch costs that occur in real time that are necessary to accommodate its real-time transactions.

6. Designating Resources and Loads

152. The existing *pro forma* tariff allows a Network Integration Transmission Service customer to designate resources that the customer owns or has committed to purchase pursuant to an executed, non-interruptible contract. The transmission provider must then plan and operate its system to be able to provide firm transmission service from these resources to the customer's load. Under the proposed Standard Market Design, the reservation of capacity for service is no longer required, since a transmission customer pays the congestion cost for transmission service. Thus, there is no longer a need for a Network Access Service customer to designate network resources to get transmission service. While the integration of resources and loads (including behind-the-meter generation) that occurs under Network Integration Transmission Service will continue, a Network Access Service customer will now request receipt and delivery points through the day-ahead scheduling process and real-time transactions.

153. Thus, we believe that the requirement to designate network resources to receive transmission service may no longer be needed. Further, we note that under the existing *pro forma* tariff the designation of network resources was used in addressing long-term resource adequacy concerns and in the planning process undertaken to ensure that the resources could be integrated. Because we are now proposing a resource adequacy requirement and a regional planning process to meet these requirements, the requirement to designate network resources may no longer be needed. (*See* Section IV.J). We request comment on whether designating network resources and loads is necessary for Network Access Service, particularly with respect to performing the integration of resources and loads.[95] Similarly, with respect to the information required to complete an application for service (Section 2 of the SMD Tariff), is it necessary for the Independent Transmission Provider to request information beyond the identity of and contact information for the customer, service term and commencement date, and receipt and delivery points for the requested service? Does the Independent Transmission Provider need to collect for each service request (but not for each transaction) the location and characteristics of the generation serving the load, detailed descriptions of the load and the customer's transmission system and owned generation?[96] In sum, do we need separate procedures for service to customers such as marketers, who do not serve load or own generation, or transmission systems and load-serving entities that have all these things? Does the integration aspect of Network Access Service require different information to be provided to the Independent Transmission Provider in order to initiate service? Should this information be provided through other means, and what would that be?

7. Substituting Receipt and Delivery Points

154. Under the existing *pro forma* tariff, choosing alternate resources to meet load required, in effect, placing a request in the queue for new service. If firm capacity were available, the customer would be permitted to use alternate points of receipt (or delivery) on a firm basis. If firm capacity were not available, the customer could choose the point(s) on a secondary, or non-firm, basis.

155. With Network Access Service, this process is no longer necessary. A Network Access Service customer can essentially access any point simply by requesting it through the day-ahead scheduling process or real-time transactions (and be willing to pay congestion costs and losses). To the extent the customer wanted to avoid the cost of congestion for the transaction, it could retain its existing Congestion Revenue Rights and acquire additional Congestion Revenue Rights for its new receipt and delivery points through an auction or secondary market.

156. Alternatively, the customer could request a ''reconfiguration'' of the Congestion Revenue Rights it holds, *i.e.*, the customer could turn in the Congestion Revenue Rights for the old receipt and/or delivery point and request Congestion Revenue Rights from the new receipt point or to the new delivery point. We seek comment on the MW quantity of reconfigured Congestion Revenue Rights that the customer should be entitled to receive. There are at least three options. One option is to allocate to the customer the MW quantity that is available specifically as a result of turning in the old Congestion Revenue Rights. Under this option, the customer would receive rights that become available by turning in the old Congestion Revenue Rights. In such a case, the MW quantity of new Congestion Revenue Rights might be different (either larger or smaller) than the MW quantity of the old Congestion Revenue Rights.[97] A second option is to allocate any MW quantity of new Congestion Revenue Rights that are physically feasible (*i.e.*, it does not adversely affect the Congestion Revenue Rights held by any other customer), including Congestion Revenue Rights that were available before turning in the old Congestion Revenue Rights. The MW quantity of new Congestion Revenue Rights under this option could also be different (either larger or smaller) than the MW quantity of older Congestion Revenue Rights. A third option is to allocate a MW quantity of new Congestion Revenue Rights that is either equal to the MW quantity of the old Congestion Revenue Rights, or, if that is not physically feasible, the

[95] The relevant sections of the SMD Tariff are Sections B.3 and B.4. While we believe that they may no longer be necessary, they remain in the tariff for ease of reference during the proposed rulemaking process. In the Final Rule, the Commission will determine if these or similar provisions need to be included in the SMD Tariff.

[96] *See* Sections B.2.2.1(iv) and (v), and Sections B.2.2.2(iii) through (vi) of the SMD Tariff.

[97] For example, a customer holding a 10 MW Congestion Revenue Right from A to B may want to exchange its existing rights for Congestion Revenue Rights from C to D. Suppose that both the A-to-B and C-to-D Congestion Revenue Rights relied on a common congested flowgate, so that the amount of A-to-B Congestion Revenue Rights and C-to-D Congestion Revenue Rights is limited by the capacity of the flowgate. However, suppose that the A-to-B Congestion Revenue Right relies more heavily on the congested flowgate than the C-to-D Congestion Revenue Right. That is, the proportion of the power flow (known as the ''power flow distribution factor'') over the flowgate in transmission service from A to B is greater than the proportion in transmission service from C to D. Thus, giving up 10 MW of A-to-B Congestion Revenue Rights may create the ability to award more than 10 MW of Congestion Revenue Rights (*e.g.,* 15 MW) from C to D. Conversely, a customer with 15 MW of C-to-D Congestion Revenue Rights could exchange them for only 10 MW of A-to-B Congestion Revenue Rights.

largest MW quantity that is physically feasible. Under this third option, the MW quantity of new Congestion Revenue Rights could never exceed the MW quantity of the old Congestion Revenue Rights. The process for acquiring and reconfiguring Congestion Revenue Rights is further described in Section IV.E.3.

8. System Impact and Facilities Studies

157. Most service requests will be resolved through the day-ahead security-constrained dispatch. Nevertheless, the Independent Transmission Provider will need to conduct system impact and/or facilities studies for service involving the interconnection of a new load or generator. The Independent Transmission Provider will also routinely perform simultaneous feasibility studies to determine the configurations of Congestion Revenue Rights that can be accommodated. Thus, except for adding references to the simultaneous feasibility studies that will be performed in response to requests for Congestion Revenue Rights, sections of the existing pro forma tariff addressing various studies will remain largely unchanged. However, as discussed in Section IV.C.8, these studies are now required to be performed by an Independent Transmission Provider.

9. Load Shedding and Curtailments

158. Under the existing *pro forma* tariff, load shedding and curtailment procedures were developed for inclusion in individual network operating agreements. These procedures should be uniform and, therefore, will be included in the SMD Tariff. In addition, we expect that the majority of constraints will be resolved through the LMP-based congestion management system, with only localized emergency/reliability contingencies (transmission line outage into a load pocket) needing to be addressed through load shedding or curtailment procedures.

159. This is a major improvement over the current tariff, as it should eliminate most or all TLRs. To the extent practicable, when system conditions require curtailment (in real time) that cannot be resolved through the congestion management system, the Independent Transmission Provider should curtail the customers whose transactions contribute to the constraint on a *pro rata* basis.[98] In addition, we propose that to the extent the Independent Transmission Provider is unable to schedule all requests for service made through the day-ahead scheduling process, those customers with Congestion Revenue Rights for their requested receipt point-delivery point combinations should be scheduled first. We seek comment as to whether this scheduling priority is appropriate. While it would grant Congestion Revenue Rights holders an additional measure of certainty of delivery, would this undermine the benefits of having a single transmission service for all customers?

160. We propose that an Independent Transmission Provider can assess a penalty for failure to curtail if a transmission customer fails to curtail after reasonable notice. The proposed penalty is the locational marginal price plus $1000 per MWh. The Commission has approved a minimum notice period of ten minutes if the curtailment is for reliability purposes.[99] We request comment on whether the Commission should continue this practice.

161. We also note that the Commission required transmission providers to incorporate procedures for addressing curtailment of parallel flows involving more than one transmission system (*i.e.*, the Transmission Loading Relief Procedure developed by NERC) as a single generic amendment to the *pro forma* tariff.[100] Under Network Access Service, procedures for addressing non-discriminatory curtailment of parallel flows will continue to be needed under emergency conditions when the use of a regional congestion management procedure set out in this proposed rule does not completely relieve a constraint.[101] Language has been added to Section 9.3, Curtailments of Scheduled Deliveries, to reflect this change.

10. Trading (Reassigning) Congestion Revenue Rights

162. Network Access Service adds the tradability that currently exists for ''firm'' Point-to-Point Transmission Service, but was not available under Network Integration Transmission Service. Customers may be able to acquire Congestion Revenue Rights from a particular receipt point to a particular delivery point directly from the Independent Transmission Provider, through a formal auction, or through secondary markets. Once a customer has these point-specific Congestion Revenue Rights, the customer may sell them at any time to another entity, whether or not that entity intends to transmit power. The sale could be for all or a portion of the amount or duration of the Congestion Revenue Rights. All resales of Congestion Revenue Rights must be reported on and conducted through the OASIS. As is currently the case in some ISOs, Congestion Revenue Rights will be traded at the price at which purchasers value the rights. The procedures for the auctions and resale of Congestion Revenue Rights are discussed in Section IV.E.3.

163. We seek comment as to whether all Congestion Revenue Rights must be sold through the OASIS, or whether some bilateral sales may be made and only reported through OASIS after the sale.

11. Ancillary Services

164. The ancillary services provided as part of the current *pro forma* tariff will largely remain the same under Network Access Service. However, certain ancillary services will be provided through organized markets with appropriate market power mitigation, as discussed *infra*. The ancillary services markets are discussed in Sections IV.F.1.d and IV.F.3.b.

D. Transmission Pricing

165. The Commission seeks to ensure transmission owners the opportunity to recover their revenue requirements for their transmission systems under Network Access Service. This charge could either be a license plate rate (charge depends on zone of delivery) or a postage stamp rate (same rate applies for all load within the Independent Transmission Provider's service area) and would be paid by all entities serving load within the Independent Transmission Provider's service area. Moreover, to facilitate trading across regions, we are proposing to change our policy on pricing of transactions that start and end in different transmission systems.

166. In addition, we are proposing to refine our policy on pricing of transmission expansions to provide incentives for market-driven solutions. To facilitate the addition of much needed transmission infrastructure, we

[98] Because we are now proposing to exercise our jurisdiction over the transmission component of bundled retail transactions and to provide a single set of rules and regulations that apply to all transmission service, the limitation imposed by the United States Court of Appeals for the Eighth Circuit on the Commission's curtailment authority over bundled retail customers is no longer relevant. *See* Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin), 83 FERC ¶ 61,098, *order on clarification*, 83 FERC ¶ 61,338, *reh'g denied*, 84 FERC ¶ 61,128 (1998), *Northern States Power Co., et al.* v. *FERC*, 176 F.3d 1090 (8th Cir. 1999), *cert. denied*, 528 U.S. 1182 (2000), *order on remand*, 89 FERC ¶ 61,178 (1999).

[99] *See* Allegheny Power System, Inc., 80 FERC ¶ 61,143 at 61,546 (1997), *order on reh'g*, 85 FERC ¶ 61,235 (1998).

[100] *See* North American Electric Reliability Council, 87 FERC ¶ 61,160 (1999).

[101] Such procedures may need to be refined in light of Standard Market Design.

propose a regional approach to transmission expansion which includes extensive participation by Regional State Advisory Committees [102] to identify the beneficiaries of a proposed expansion and how costs for that expansion should be recovered.

1. Recovery of Embedded Costs

167. Under the existing *pro forma* tariff, there are two types of transmission services—Network Integration Transmission Service, which is designed for the integration of resources and loads, and Point-to-Point Transmission Service, which is generally used to export power from one transmission system to another (through-and-out service).

168. To recover the embedded costs of the transmission grid, the Commission has historically permitted transmission providers to assess an access charge, in the form of a load ratio share charge or a per kW per month charge, on all transactions taking place on the transmission provider's system.[103] For a single transmission utility, these charges usually take the form of a ''postage stamp'' rate (*i.e.*, the same charge for all customers'' use of the utility's grid) and, for an ISO or RTO, a ''license plate'' rate (*i.e.*, a different charge for the use of the entire regional transmission system that is based on the revenue requirement of the transmission owner's facilities, or ''zone,'' where the transaction sinks).[104] The access charge is assessed on all transactions making use of the transmission provider's system, including transactions where the generator and load are located within the transmission provider's system and where either the generator or the load (or both) are located outside of the transmission provider's system.

169. While this method of pricing has been effective in recovering a transmission provider's revenue requirement, some changes are required to reflect the new Network Access Service and to address unintended consequences of the current rate design. First, we propose that transmission owners recover embedded costs through an access charge assessed mainly to load-serving entities, based on their respective shares of the system's peak load, *i.e.*, their load ratio shares. Our goal is to minimize the distorting effects that an access charge can have on economic choices. We propose to assess access charges primarily on loads, but not on generators, because the economic choices of loads (such as where to locate) are less likely to be affected by access charges than are the choices of generators.[105] Moreover, even if access charges were imposed on generators or other market participants, it is likely that they would pass along most or all of their access charges to their customers, so that loads would ultimately bear most or all of the transmission fixed costs.

170. Second, we propose to eliminate all ''rate pancaking,'' which involves charging separate embedded cost charges for moving power over separate Independent Transmission Provider service areas. We propose to eliminate rate pancaking both within an Independent Transmission Provider's service area and between service areas. Rate pancaking impedes the ability of distant generators to compete with nearby generators by imposing charges to transmit energy from distant generators that are unrelated to actual variable transmission costs. Assessing the access charge primarily to load-serving entities based on their load ratio share rather than on the number of service areas over which energy is transmitted increases generation competition by allowing distant generators to compete more easily with nearby generators.

171. As discussed further below, we propose that customers paying access charges would receive Congestion Revenue Rights (or alternatively, revenues from the auction of Congestion Revenue Rights). Thus, in exchange for paying the fixed costs of the transmission system, those paying access charges would receive the financial benefits—the stream of congestion revenues—resulting from usage of the transmission system. In addition, we seek to minimize cost shifts that could result from our proposal, and we propose to maintain as much as possible the explicit and implicit transmission rights currently held by customers. Thus, customers currently receiving Network Integration Transmission Service and firm Point-to-Point Transmission Service under the existing *pro forma* tariff would receive Congestion Revenue Rights based on their existing service levels. However, there are two issues regarding access charges and the allocation of Congestion Revenue Rights on which we specifically seek comment.

172. First, we seek comment on the treatment of existing customers taking long-term firm Point-to-Point Transmission Service that are not load-serving entities. Such customers currently pay an embedded cost charge in order to receive firm Point-to-Point Transmission Service under the Order No. 888 *pro forma* tariff. We believe that it would be inequitable for customers to receive an initial allocation of Congestion Revenue Rights unless they also pay a share of transmission embedded costs. We also believe that it would be inequitable for customers to pay a share of transmission embedded costs without receiving an initial allocation of Congestion Revenue Rights. Thus, we seek comment on two options. One option is for these customers to continue paying their embedded cost charges in exchange for receiving Congestion Revenue Rights that reflect their current levels of Point-to-Point Transmission Service. This option would help minimize cost shifts, while maintaining the transmission rights currently held by these customers. On the other hand, this option would recover a portion of embedded transmission costs from customers that are not loads. The second option is to eliminate the access charges for these customers while also allocating no Congestion Revenue Rights to them. This option avoids recovering embedded costs from entities that are not loads. However, it would result in some shifting of the responsibility for recovering embedded costs, and it would fail to maintain the transmission rights currently held by these customers. We seek comment on the merits of these two options, as well as whether the Final Rule should select one option or, alternatively, allow customers to choose between them.[106]

[102] Regional State Advisory Committee as discussed more fully in Section IV.K.

[103] A Network Integration Transmission Service customer pays a monthly demand charge based on its load ratio share of the transmission provider's monthly transmission revenue requirement. The customer's load ratio share is based on the customer's hourly load coincident with the transmission provider's monthly transmission system peak. The firm Point-to-Point transmission customer pays a monthly demand charge for each unit of capacity that it has reserved.

[104] Both PJM and New York ISO use a license plate rate design. PJM and New York ISO have different rate designs for exports and wheel-through services. PJM uses a weighted average of the charges of all transmission for these types of transactions. New York ISO uses the transmission charge of the owner of the intertie that serves as the point of delivery to the adjacent system.

[105] Point-to-Point customers wanting to receive a direct allocation of Congestion Revenue Rights would also pay the access charge, as discussed below.

[106] We propose that Congestion Revenue Rights be directly assigned only to long-term firm customers, consistent with the existing *pro forma* tariff's right of first refusal. Thus, short-term and non-firm point-to-point customers would not receive Congestion Revenue Rights under direct assignment. These customers, therefore, may wish to structure their contracts such that they expire at the time Standard Market Design is implemented. This way, while they would not receive Congestion Revenue Rights, they also would no longer be paying an access charge.

173. The second issue concerns the treatment of load-serving entities in retail open access states that attract loads away from their traditional utility suppliers. Under our proposal, a new load-serving entity that attracts load from other suppliers would be assigned a share of embedded costs—costs previously assigned to other suppliers. In areas where there is no Available Transfer Capability for additional Congestion Revenue Rights, we seek comment on how such new load-serving entities should receive an allocation of the customer's former load-serving entity's Congestion Revenue Rights. We propose that Congestion Revenue Rights ''follow the load.'' Thus, Congestion Revenue Rights previously allocated to other suppliers whose loads (and access charges) have been reduced would be reallocated to the new load-serving entities.

174. We propose to permit the use of license plate rates such as those that are currently in effect within ISOs. We seek comment, however, on whether we should retain license plate ratemaking only for a transitional period and at some later date, require that all regions have postage stamp rates. Should the Commission upon the recommendation of a Regional State Advisory Committee accept an embedded cost recovery mechanism for the region which may vary from neighboring regions?

175. To better illustrate the pricing proposals we have included Appendix F which identifies by customer types whether and under what circumstances they will pay the access charge and/or receive Congestion Revenue Rights under Network Access Service.

2. Rates for Bundled Retail Customers

176. When a vertically integrated utility joins a regional organization such as an ISO or RTO, the Commission has required that the utility execute a service agreement under the regional transmission provider's transmission tariff. For instance, the Commission required the vertically integrated utilities in GridSouth to execute a service agreement under the GridSouth transmission tariff, thus ensuring that these utilities would take service for their bundled retail load under the same terms and conditions as all other users of the grid.

177. With respect to whether the GridSouth transmission charge should be applied to the bundled retail load, the Commission permitted the utilities to pay the transmission portion of the bundled retail rate, but required that the service agreement explicitly state the rate to be charged.[107] The Commission added that having vertically integrated utilities pay GridSouth for transmission to serve their bundled retail customers does not make those utilities' retail rates subject to our jurisdiction. Rather, the Commission stated its willingness to accommodate the utilities paying GridSouth a transmission rate equal to the transmission component of their bundled retail rates, as long as the price is clearly stated, reduced to writing in contracts with GridSouth, and is not accomplished by omission.[108]

178. Now that the Commission is asserting jurisdiction over all transmission service in interstate commerce, including that for bundled retail service, the question arises as to whether different charges for transmission service for wholesale and bundled retail customers should be permitted. Allowing different rates for wholesale and bundled retail customers could lead to undue discrimination if the rate setting policies of the state and the Commission differ significantly. The Commission seeks comment on whether all customers should be charged the same transmission rate either upon implementation of Standard Market Design or after a reasonable transition period of four years.

3. Inter-Regional Transfers

179. Under current rate designs, a user that transmits power from one region to another would pay two transmission charges to recover the embedded costs of the transmission provider from which power was exported as well as the embedded costs of the transmission provider where power is delivered to load. As long as transmission owners have an opportunity to recover their embedded costs, to increase competition, we propose to prevent customers from being assessed multiple transmission charges.

180. We have concluded that rate treatment for inter- and intra-regional transactions should be consistent to avoid creating artificial incentives or disincentives for trade across regions. Thus, the design of rates for Network Access Service should eliminate the payment of multiple access charges, such that only one access charge is paid for power to reach load. Accordingly, an export and through-and-out transaction originating in an Independent Transmission Provider's system and terminating at a load in another Independent Transmission Provider's system would pay only the access charge for the transmission system where power is ultimately delivered to load.[109] This will encourage broader areas of competition by eliminating multiple access charges, and in particular would reduce the harsh inequities of regional boundary definition on those customers near such boundaries.

181. It has become apparent that transmission pricing across RTO borders can have a significant impact both on power purchasing decisions and on RTO formation. A customer's choice as to whether to purchase power from a generator located within the same RTO or a neighboring RTO is directly affected by the fact that one generator faces an additional access charge to reach the RTO in which the load is located. This additional access charge may cause the sale to become uneconomic.[110]

182. In addition, decisions on which RTO/ISO to join may be affected by inter-regional pricing. Choices driven by the economics of transmission owner's merchant function's trading patterns, rather than by the most rational and efficient aggregation of transmission assets for a particular region, could result in oddly configured RTOs.

183. Rate pancaking across the numerous transmission owning utilities that comprise the RTO has been eliminated by the implementation of license plate rates, while continuing to provide an opportunity for the transmission owners to recover their full revenue requirements. We propose that the same or a similar rate structure should be applied to inter-regional transfers. In a competitive market environment, reliability and the supplier's cost of generation, rather than sunk transmission costs, should be the primary drivers for a customer's choice of power suppliers. To the extent rate design facilitates that result, transmission owners would have a greater incentive to join an RTO based on where their transmission facilities most benefit customers and markets, not on where their generators have better opportunities to make off-system sales

[107] Carolina Power & Light Co., *et al.*, 94 FERC ¶61,273 at 61,999, *order on reh'g*, 95 FERC ¶61,282 (2001).

[108] 95 FERC ¶61,282 at 61,991.

[109] However, the transaction would still be responsible for applicable congestion charges and transmission losses in the originating and any intermediate transmission systems.

[101] *E.g.*, a load and Generator 1 with a cost of $25 are located in RTO A, and a competing Generator 2 with a cost of $24 is located just across the border in RTO B. On its face (and absent congestion), it appears that the load should choose Generator 2 in RTO B. However, because Generator 2 faces a $2 transmission charge from RTO B, it is unable to compete with Generator 1 even though it is a more efficient unit simply because of the additional access charge.

(*i.e.*, an access charge for exporting power from one region to a neighboring region should not be the deciding factor).

184. However, absent other adjustment mechanisms, if customers going through and out of an RTO are no longer charged access fees by that RTO for transmission service, these costs would instead be borne by the load served by the RTO through the existing load ratio share methodology.[111] Under the commonly used license plate rate design, load within a particular RTO zone would pay that transmission owner's full embedded costs, including the portion that is currently contributed by through-and-out customers. This may create problematic cost shifts for certain transmission providers that currently receive a significant amount of revenue from exports and wheel-throughs (*e.g.*, AEP and Cinergy). While simply eliminating the transmission charge for through-and-out service may avoid the skewing of purchase and sale decisions by inter-regional transaction charges, it will result in cost-shifting and may stifle new transmission investment since state regulators will not generally favor having their customers pay for facilities that may primarily benefit other states.

185. Therefore, we propose to create a mechanism that recognizes the import/export quantities in establishing the revenue requirement to be recovered through the access charge. We seek comment on two approaches that could be used.

186. One method would be to have the ''source'' Independent Transmission Provider allocate a portion of its revenue requirement to the ''sink'' Independent Transmission Provider's transmission customers. An Independent Transmission Provider's revenue requirement could be reduced by the amount of revenues associated with through-and-out service and that portion of the revenue requirement would then be included as uplift in the scheduling charge paid by all customers of the sink Independent Transmission Provider in whose service area the power sinks. Under this approach, costs would not be shifted from the beneficiaries of the inter-regional transaction to the load on the source side of the transaction. At the same time, embedded cost recovery would not interfere with short-run efficiency, since embedded costs would not be recovered in individual inter-regional transactions, but would instead be recovered through uplift from all customers in the zone of the sink Independent Transmission Provider. This method would require a projection of inter-regional transfers and a rate filing to accomplish the re-allocation of costs between Independent Transmission Providers. It would also require a decision as to how narrowly to focus the cost allocation (*e.g.*, RTO to RTO, export zone to import zone).

187. Alternatively, under a revenue crediting approach, inter-regional transfers could be priced at the load ratio share charge (or a similar transmission charge)[112] and the inter-regional transaction charges would be netted out over some time period (*e.g.*, one month or one year). This method would assign the inter-regional charges to all customers within the sink Independent Transmission Provider. The cost of transmission on a neighboring Independent Transmission Provider associated with net imported power could be charged to all of the net importing Independent Transmission Provider's customers through the Independent Transmission Provider's scheduling charge. The revenues would be returned to all transmission customers within the net exporting Independent Transmission Provider.

188. We seek comment on whether there should be a uniform cost allocation of inter-regional costs among all zones within an Independent Transmission Provider's system. For instance, there will likely be opposition to a region-wide charge by customers who do not import power. To address this concern, the inter-regional transfers could instead be netted out between zones within neighboring Independent Transmission Providers. This way the costs would be assigned to all customers within the import zone and the revenues would be returned to the export zone. These transmission costs could be assigned to the zone where the power was imported as if the neighboring Independent Transmission Provider's facilities were part of that zone. Likewise, the zone where exports leave an Independent Transmission Provider would receive the transmission payments associated with the exports. It is possible that the revenue sharing plan used by ISOs with license plate rates to resolve intra-ISO, interzone transactions could be broadened to encompass inter-RTO transactions.

189. As noted above, the proposed rule advocates treating inter- and intra-regional transmission pricing the same. As explained elsewhere, customers within the region who pay the access charge will be entitled to Congestion Revenue Rights or the revenues from the auction of those rights. We propose a similar result for inter-regional transactions when customers in one region are paying a portion of the embedded costs of another region. We seek comment on how to assign Congestion Revenue Rights to the customers of the importing region. For example, if Midwest ISO is a net exporter to PJM, customers on PJM's system will be obligated to pay a portion of Midwest ISO's embedded costs. PJM's customers could receive a proportionate share of Midwest ISO's Congestion Revenue Rights.

4. Application of Inter-Regional Pricing to Parallel Path Flows

190. To the extent the Commission adopts a true-up methodology for recovering the costs of through-and-out services, should a similar pricing methodology be applied to parallel path flows? Parallel path flows are comparable in that one region benefits by the use of a neighboring region's transmission facilities. Parallel path flows are currently resolved through cooperation. An alternative method would be to price all uses of the grid. We seek comment as to how cost impacts of parallel path flows across regional borders should be addressed.

5. Pricing of New Transmission Capacity

191. The existing transmission grid has fallen far behind the demands that have been placed on it. Over the last ten years, we have seen a strong increase in the amount of new generation, which has been built largely in locations that make the most economic sense for the builder of the generation (i.e., where land is affordable and economic sources of fuel, water and labor are near). However, we have yet to see a parallel jump in construction of transmission infrastructure. The absence of needed new transmission facilities has led to more and more congestion, which hinders customers from seeking and depending on more distant and competitive supply choices.

192. The sluggishness of transmission construction is largely because: (1) Siting transmission is a long and contentious process; and (2) mismatches between those who benefit from the new facilities and those who pay for them, particularly when the two affected sets of customers are served by different transmission providers, are often more than enough to make sure the new facilities do not get built. The Department of Energy's 2002 National Transmission Study points to state-by-state siting approval, a lack of regional

[111] This would also be true for a non-RTO Independent Transmission Provider.

[112] An explanation of how this charge may be calculated is contained in Appendix F.

institutions and a lack of clarity in regulatory pricing policy as several of the barriers to transmission investment.[113]

193. The Commission's pricing policy for network upgrades, whether for reliability or economic reasons, has traditionally favored ''rolled in'' pricing, where all users pay an administratively determined share of new facilities. This policy was based on the rationale that the transmission grid is a single piece of equipment such that system expansions are used by and benefit all users due to the integrated nature of the grid. This method forms the basis of the pricing proposal in the Generation Interconnection proposed rule.

194. If the expansion is for region-wide reliability, there is little disagreement as to who should pay for the necessary facilities—all ratepayers. Likewise, interconnection facilities are non-controversial; there is general agreement that these facilities should be directly assigned to the interconnecting generator.

195. What we see, however, is that economic expansions that would remove congestion and allow customers to reach more distant power supplies are the most difficult to get sited. This is at least in part because state siting authorities have no interest in siting a line that benefits a particular generator or a distant load in another state because to do so would require the load on the constructing public utility's system to pay for the new facilities. The state authorities, at a minimum, need assurance that the costs of that expansion will be paid for by those who benefit from the expansion in order to have sufficient incentive to site the new facilities.

196. Our goal is to remove any cost recovery impediments to transmission expansion so that needed upgrades get built now. Traditional means of expansion pricing may not be the most effective way of encouraging new transmission infrastructure, in part perhaps because they do not take into account the wide regional benefits of higher voltage upgrades that can accrue beyond a single transmission owner's system.

197. We believe that a more precise matching of beneficiaries and cost recovery responsibility would encourage greater regional cooperation to get needed facilities sited and built. Our preference is to allow recovery of the costs of expansion through participant funding, *i.e.*, those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it.

198. The Generator Interconnection proposed rule introduced the idea that participant funding may be an acceptable pricing policy where an independent entity determines: (1) The cost of and responsibility for needed upgrades; (2) congestion price signals to which the customer responds (along with Congestion Revenue Rights); and (3) the assumptions underlying the power flow analysis.[114]

199. The Commission envisions that, under Standard Market Design, the Independent Transmission Provider will perform all of these functions, which will allow the Commission to consider the use of participant funding. However, full compliance with Standard Market Design will take some time. We are eager to see new infrastructure in place as soon as possible and believe that participant funding will be a useful tool to make that happen. Accordingly, we propose that, for proposed transmission facilities that are included in a regional planning process which is conducted by an entity, whether an RTO, ISO, or other independent entity, that is independent, we will consider participant funding for that project.

200. In the absence of independence, we would apply a default pricing policy that would recognize the regional benefits of transmission expansions. Under this default policy, we propose to roll-in on a region-wide basis all high voltage network upgrades of 138 kV and above. Since lower voltage, sub-regional transmission needs are less likely to benefit the whole region, the cost of network facilities below 138 kV could be more appropriately allocated to a sub-region (*e.g.*, a single transmission owner or a ''license plate'' zone) where the expansion facilities will be located. Consistent with our proposal for interregional transmission service pricing, costs would be allocated to the region that benefits from the expansion, which may not be the same as the region in which the expansion facilities are located. This proposal recognizes that high voltage expansions can have benefits beyond the borders of the local transmitting utility and, therefore, assigns a portion of these costs to more distant beneficiaries.

201. Further, as we explain in Section IV.G.3, Regional Planning Process, we encourage the formation of Regional State Advisory Committees, which, in addition to facilitating the siting of regional expansions, can enable states to work together to identify beneficiaries of expansion projects and make recommendations on pricing proposals. To the extent there is agreement within the Regional State Advisory Committee, the Commission would look favorably on a pricing proposal by the Regional State Advisory Committee if it is consistent with the FPA. Such a proposal might take the form of roll-in, an assignment to beneficiaries, or some combination of the two.

202. We seek comment whether these pricing proposals are appropriate to meet our goal of expediting needed infrastructure investment or whether another method would be more effective.

E. The New Congestion Management System

203. Under Network Access Service, all transmission customers may request transmission service. The Independent Transmission Provider must honor all valid transmission requests where there is sufficient capability, *i.e.*, when there is no transmission congestion. However, when there is transmission congestion we propose to require that all Independent Transmission Providers allocate scarce transmission capability using a price system. Specifically, we propose to require that all Independent Transmission Providers manage congestion using a system of LMP and Congestion Revenue Rights. Under LMP, the price to transmit energy between any receipt point and delivery point reflects the marginal cost (including the marginal opportunity cost) of such transmission service, and the price of energy at each location reflects the marginal cost (as reflected in participants' bids) of producing energy and delivering it to that location.

1. Locational Marginal Pricing

204. LMP is the method that is currently used for managing congestion in the regional markets run by both PJM and New York ISO. It is also proposed to be adopted as the congestion management system for ISO-New England in 2003 and for the California ISO in its proposed market redesign.[115] Marginal pricing, a fundamental concept in economics, is the basis for LMP.[116] Marginal pricing is the idea

[113] *See* DOE National Transmission Grid Study.

[114] The Commission is currently reviewing extensive comments on this topic in that proceeding.

[115] *See* California ISO's Comprehensive Market Design Proposal, Docket No. ER02–1656–000 (May 1, 2002); *see also* California Independent System Operator Corp., 100 FERC ¶ 61,060 (2002).

[116] It is a widely accepted principle of economics that markets work efficiently when prices reflect marginal costs. *See* Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions,* The MIT Press, Cambridge, Massachusetts, reprinted 1988, pp. 63–70. The economic rationale for applying marginal cost pricing to an electricity network using the concepts of LMP was presented in Schweppe, F.C., *et al., Spot Pricing of Electricity,* 1988, Norwell, MA, Kluwer Academic Publishers; and Hogan, William W., ''Contract Networks for Electric Power Transmission,'' *Journal of Regulatory Economics,* 1992, vol. 4, pp. 211–242.

that the market price should be the cost of bringing the last unit to market (the one that balances supply and demand). LMP in electricity recognizes that the marginal price may differ at different locations and times. Differences result from transmission congestion which limits the transfer of electricity between the different locations.[117] The marginal price of energy at a particular location and time—that is, the energy LMP—is the additional cost of procuring the last unit of energy supply that buyers and sellers at that location willingly agree on to meet the demand for energy. That is, it is the price that ''clears the market'' for energy.[118]

205. LMP is a market-based method for congestion management. Congestion is managed through energy prices and transmission usage charges (congestion and loss charges) determined in a bid-based market. When there is no congestion anywhere on the system (when there is enough transmission capacity to get power from the cheapest available generators to all potential buyers) there will be only one energy price in the transmission system, the price bid by the last, or marginal, generator that provides energy or load that offers to reduce its demand.[119] When there is congestion, the cheapest generators may be unable to reach all their potential buyers. Consequently, when there is congestion there may be many different energy prices across the transmission system.[120] Under LMP, the Independent Transmission Provider will establish separate energy prices at each node on the transmission grid and separate prices to transmit energy between any two nodes (receipt and delivery points) on the grid. These prices reflect the cost of congestion. LMP relies on economic redispatch in managing congestion. Redispatching means decreasing the energy the Independent Transmission Provider obtains in front of the constraint (where the power is flowing from) and increasing the energy the Independent Transmission Provider obtains behind the constraint (where the power is flowing to). The cost of redispatch is the basis for the congestion charges under LMP. If a customer is willing to pay the marginal cost of redispatch, which it signals through its bids, the Independent Transmission Provider will schedule the transmission service.

206. For example, assume there is congestion or a constraint on one transmission interface. Some low-cost generators may not be able to deliver energy to load on the other (import) side of the constraint. So, they will need to reduce their production because of the constraint. To signal these generators to reduce their production, the energy price that these generators would receive would be lowered. To replace the low-cost generation, more expensive generators on the other side of the constraint (export) must be dispatched. To signal to these higher cost generators that they should increase their production, the energy price they would receive would increase. As a result the energy price on each side of the transmission constraint would be different. The energy price would be lower on the side where more suppliers are trying to sell out of the region than can be accommodated by the transmission capacity. The energy price would be higher on the side where more expensive local generation must be used because of the transmission constraint. As discussed further in Section IV.F., for purchasers of energy in the Independent Transmission Provider-run spot markets, the LMP at the node closest to them is their delivered power cost (energy charge plus transmission charge). The generators are then paid the LMP at the nodes closest to them.

207. For customers buying energy through bilateral contracts rather than in spot markets, the transmission usage charge would reflect the marginal cost of transmission between a receipt point and a delivery point.[121] In the above example, the difference would be the marginal cost of moving energy from the import to the export side of the constraint which should equal the difference in the energy price on the import and the export side of the constraint. In other words, the transmission usage charge for bilateral transactions would be the difference between the LMP at the receipt point and the delivery point. When congestion exists, the difference in energy prices to transmission users is a price signal that reflects the marginal cost of economic dispatch of resources necessary to accommodate the transmission service. Those who place a higher value on the transmission capacity and the value of the ultimate delivered electricity, will be willing to pay higher transmission usage charges. Also, because transmission usage charges for bilateral transactions are based on the differences in spot market energy prices, the proposed congestion management system would not bias a customer's choice between purchasing energy through the spot market versus a bilateral transaction.

208. LMP uses a financial instrument called a Congestion Revenue Right to provide customers with price certainty for transmission service.[122] A Congestion Revenue Right is a financial tool that allows a customer to protect itself against the costs of congestion. A Congestion Revenue Right ensures that the holder of that right will be protected

[117] Prices may also vary based on transmission losses. For purposes of simplification this discussion focuses on the differences due to energy prices alone.

[118] Under LMP, all suppliers selling at a location receive the market clearing price, including those who offer in their bids to sell for less. Similarly, all buyers purchasing at the location pay the market clearing price, including those who offer in their bids to purchase at a higher price. An alternative policy would be to pay each seller its bid price (and perhaps, to charge each buyer its bid price). We propose a single market clearing price for several reasons. First, it encourages sellers to submit bids that reflect their marginal costs (and thus, the sellers selected in the energy auction are more likely to be the sellers with the lowest actual costs). Sellers without market power could not increase the market price by increasing their bids, so bidding above their marginal costs would have no benefit to them. Bidding above marginal cost would merely create the risk that the seller would lose in the auction when the market price was higher than the seller's marginal costs, and thus, the seller could have earned a profit. Moreover, by paying all sellers the market clearing price, sellers with marginal costs below the market clearing price would receive revenues to help recover their fixed costs. A policy of paying each seller its bid would encourage sellers to bid above their marginal costs, since doing so would be the only way for them to earn a profit. As a result, the sellers selected in the auction would not necessarily be the sellers with the lowest actual costs. Moreover, if the pay-as-bid policy were applied only to sellers (and not to buyers), so that buyers were charged the average payment made to sellers, buyers would face a price that was lower than the highest accepted seller's bid. This result would encourage inefficient purchases and poor demand response. For example, on a hot day when the highest accepted seller's bid is $1000/MWh but the average payment to sellers is $400/MWh, charging buyers $400/MWh under pay-as-bid would encourage less demand response than a market clearing price policy of charging $1000/MWh. If the pay-as-bid policy were applied to both sellers and buyers, then the revenue collected from buyers would usually differ from the revenue paid to sellers.

[119] The operation of the bid-based auction for energy is described further in Section IV.

[120] Because the transmission grid is a network, reducing transmission service between one receipt point—delivery point pair (*e.g.,* from A to B) may free up transmission capability for transmission service between a different receipt point—delivery point pair (*e.g.,* from C to D), albeit not necessarily on a MW-for-MW basis. For example, reducing service from A to B by 2 MW may allow an additional 1 MW of transmission service from C to D. If so, the price to transmit 1 MWh of energy from C to D must reflect at least what a customer denied 2 MW of service from A to B would have been willing to pay.

[121] Transmission losses will also be recovered through the transmission usage charge and included in the energy prices under LMP.

[122] As discussed above, we also propose that Congestion Revenue Rights would provide a scheduling priority in certain circumstances.

against congestion costs for the transmission service covered by that right in the day-ahead market.[123] Once the day-ahead market closes, all customers pay for the service requested and, if they hold Congestion Revenue Rights, are paid congestion costs associated with those rights. Thus, the customer has bought and paid for a quantity of transmission at a specified price.

209. Any changes a customer wants to make to the transmission service it has scheduled in the day-ahead market must be accomplished in the real-time market at real-time prices, which may be different from the day-ahead prices. A customer wanting less transmission service than it requested and received in the day-ahead market would effectively sell back to the market the amount of unused service. Conversely, a customer needing an additional amount of transmission service could buy the additional amount of service in the real-time market. No congestion revenues are paid to Congestion Revenue Rights holders for transactions made in real-time market.[124]

210. The LMP system for congestion management is better suited to manage congestion in a competitive market than the congestion management system under the Order No. 888 *pro forma* tariff (*pro rata* curtailment) because LMP allocates scarce transmission capacity to those who value it most and it relies on an incentive system (*i.e.*, it assigns congestion costs to the transactions that cause the congestion) that encourages market participants to buy and sell power in a manner that is consistent with the reliable operation of the system. Under an LMP system, market participants have greater commercial flexibility in arranging transactions. Market participants have the ability to signal whether they are willing to buy their way through transmission constraints. Under the current system they do not have the ability to do that, in part because transmission providers do not have a mechanism for recovering the cost of economic redispatch. Currently, these types of transactions would not be scheduled because of the existence of congestion. Also, Network Access Service customers would have the ability to voluntarily resell their Congestion Revenue Rights when others value them more highly. Because market participants will see and be responsible for the full effect of their decisions on congestion costs, each have an incentive to manage its own transactions in a way that is consistent with a least-cost dispatch consistent with reliable system operations.

211. The proposed SMD Tariff lays out the general framework and the basic rules for LMP. It is based on the best practices we have seen. We recognize that in certain regions there may need to be additional rules or changes to accommodate specific regional requirements. We also recognize that over time there likely will be a need to update the tariff provisions to offer new service options or to further refine the market rules. The *pro forma* tariff is not intended to be a static document, but rather one that will evolve over time and meet the needs of the marketplace. We seek comment on how best to recognize this need for regional variation and the need for continued refinement in the rules.

212. One concern that has been expressed in the Standard Market Design conferences and in comments on the Working Paper is that while LMP may work well with systems that are dominated by thermal plants, it may not work in systems that primarily rely on hydroelectric resources. In particular, the Pacific Northwest is concerned that an hourly bid-based system with LMP may be in conflict with Northwest resource uses, practices and obligations, which are dominated by hydroelectric generation. Much of this is from ''run-of-river''[125] facilities that cannot store water, and at which energy is lost if a generator does not run when water is available. Because the decision to run is virtually automatic, many Northwest parties see no need for a bidding system. Also, many of the hydroelectric facilities of the Columbia River System must coordinate their operations; whether a downstream facility runs depends on whether an upstream dam runs and releases water. Some of this coordination is among facilities in the United States and Canada and is subject to international treaties. There is a concern that a bid-based system with LMP, which requires individual generators to bid independently against one another, ignores this cooperation or even would view such cooperation as collusion in a market system. Some coordination agreements assure that low-cost transmission will be made available to implement the coordination, and there is a concern that LMP congestion pricing may be incompatible with these agreements.

213. Northwest parties note that while annual costs in a thermal system are minimized simply by minimizing the costs in every individual hour the same does not hold true in a hydropower system. A hydroelectric dam with stored water has a marginal running cost close to zero, however, this does not mean that it should be dispatched first every hour. Rather, the value of hydropower over time depends on when that stored energy system can best be released to minimize costs over a season, a year, or even a multi-year period. Thus, there is a concern that in a hydropower system, a congestion management and energy spot market designed to minimize hourly costs will not minimize costs over a longer period.

214. Moreover, commenters have noted that decisions about water use in the Northwest are based on more than electric power cost minimization. Decisions about use of hydropower facilities involve coordinated trade-offs among power needs, the needs of fish and wildlife, irrigation, flood control, recreation and other factors, which may be difficult to reflect in the bids of individual units. Some parties in the Northwest acknowledge that a bid-based LMP system could be adapted to meet the objections above but are concerned either that such a system may be imposed without adaptation or that the adaption will be done poorly. There is also concern that adaptation to a bid-based security-constrained system may reopen such issues as transmission priorities and preference power allocations that have been settled over many years of negotiation based on factors other than market efficiency. Finally, Northwest parties worry about obtaining sufficient Congestion Revenue Rights to protect against congestion charges.

215. We believe that the proposed Standard Market Design would work well in every region and for all types of fuel sources; we believe that the concerns expressed by participants in the Pacific Northwest can be accommodated within the LMP system we propose. First, use of the Independent Transmission Provider's bid-based spot energy markets would be

[123] For example, a customer holding Congestion Revenue Rights could be charged the congestion costs (*e.g.,* $10 MWh) and then receive a credit on the same bill for congestion revenues (*e.g.,* $10 MWh). So, the net congestion costs paid by the customer is $0. The customer, however, would have to pay for transmission losses.

[124] For example, a customer schedules and receives 100 MW of transmission service the day ahead at a congestion cost of $2/MW. The customer pays the $2/MW of congestion charges to the Congestion Revenue Rights holder (which could be itself). The customer may later decide it only needs 90 MW. It could then sell in the real-time market the unneeded 10 MW. If congestion in the real-time market is $3, the seller would receive $3/MW (or $30) for the sale of the 10 MW of transmission service from the buyer of the transmission service.

[125] Run-of-river facilities use the natural flow of the river to generate electricity. They typically divert water from a nautral channel, run the water through a turbine to produce energy and then return the water to the natural channel downstream of the turbine.

optional. No one would be required to bid into these markets (except when market power mitigation is imposed).[126] Hydropower generators could choose to self-schedule without submitting a price bid. As a result, the bilateral contractual energy arrangements of the Northwest would be unaffected. Thus, for example, hydropower facilities along a common waterway that wish to develop a coordinated schedule without submitting energy price bids would be free to do so. Also, hydropower facilities that must consider non-price factors such as the needs for irrigation, flood control, and fish and wildlife in their scheduling decisions could do so through the self-scheduling feature.

216. For hydropower generators that wish to participate in the Independent Transmission Provider's spot energy markets, the Standard Market Design that we propose can accommodate the special features of hydropower facilities. Suppliers would be allowed to reflect their opportunity costs in their bids; bids need not be limited to marginal running costs. Also, generators such as hydropower facilities would have the option (but not the requirement) of requesting the Independent Transmission Provider to schedule the generator's designated MWhs over the highest priced hours of the day, to economically optimize hydropower production over the day. LMP is a result of a least-cost dispatch of the resources available to the transmission system in a manner that recognizes both the operational limits of those resources and the operational limitations of the transmission system. As a result, customers' loads can be met at the lowest total cost (as reflected in the submitted bids) consistent with the reliable operation of the system, which should be the objective on any system regardless of the resource base of the transmission system.

217. In short, we see no reason why the proposed Standard Market Design would prevent hydropower generators from operating in a way that accommodates their special features. Indeed, we believe that the LMP system would aid hydropower generators in optimizing the economic value of their resources within their legitimate operational constraints, because the prices for energy and transmission would signal the economic costs of providing energy and transmission service at different locations and time periods.

218. Finally, our proposal here would not abrogate existing pre-Order No. 888 transmission contracts, so customers holding these rights could continue their existing services under the existing contractual provisions. In addition, this proposal would allocate Congestion Revenue Rights or auction revenues to parties based on their recent historical usage of transmission. Thus, customers receiving transmission service under the Order No. 888 *pro forma* tariff, as well as entities previously serving bundled retail load outside the *pro forma* tariff, would receive Congestion Revenue Rights to protect against congestion charges.

219. We agree that the operational limits of both the resources and the transmission systems need to be fully considered in the design of the specific market rules. For example, there is likely a need to calculate opportunity costs for hydroelectric resources differently from thermal plants. These differences can affect market mitigation measures. However, we are concerned about whether different market designs can be in place in the Northwest and the rest of the West, and ask for comment on whether the entire West must have a common set of market rules to eliminate seams and prevent manipulation.

220. In the SMD Tariff we propose to include several different types of Congestion Revenue Rights to allow customers to protect against congestion costs. For example, one concern that we have heard from customers and suppliers in the Northwest is that a receipt point-to-delivery point Congestion Revenue Right may not work to effectively manage congestion on a system that utilizes several different hydroelectric facilities on a contingent basis to serve the same delivery points. A Congestion Revenue Right that recognized the contingent nature of the supply sources would be more valuable to customers in this instance. We believe that developing these types of Congestion Revenue Rights is possible and we propose to work with the regions to develop variations to meet regional needs. The congestion management system that we propose is flexible enough to accommodate these types of regional variations. Such variation and flexibility should not impinge on the development of a seamless electric grid.

2. LMP and Energy Markets

221. To implement LMP, the Independent Transmission Provider must operate an energy market to determine the marginal cost of redispatch. We propose to require that the Independent Transmission Provider operate both a day-ahead and a real-time energy market to manage congestion.

222. The Commission proposes to use real-time markets for energy to resolve energy imbalances. Under the proposal, the transmission customer would be charged the real-time price of energy for any imbalance, *i.e.*, the difference between the energy the transmission customer schedules a day ahead on the system and the amount that it takes off the system in real time. The real-time price of energy is determined through a security-constrained, bid-based energy market run by the Independent Transmission Provider. The Independent Transmission Provider uses the bids to select the lowest-cost energy within the operational limitations of the transmission system. These same procedures will be used to resolve imbalances for all users of the transmission system.

223. The Commission also proposes that the Independent Transmission Provider operate a security-constrained, financially binding day-ahead energy market that is operated together with a day-ahead scheduling process for transmission service.[127] The day-ahead market for energy will allow the Independent Transmission Provider to manage congestion that arises in the day-ahead scheduling process.[128]

224. The day-ahead energy market is a bid-based market. Sellers submit bids that indicate the quantities of power they will offer for sale in each hour of the next day and the price for that power at each location (node).[129] The price for the power may vary based on the quantities that are offered for sale. The differences in bid prices recognize that a generator's marginal cost of producing power can vary at different quantity levels because it operates more efficiently at certain output levels than others. Also, at the highest output levels, there may be additional opportunity costs because of an increased risk of a unit outage. Buyers also submit bids indicating the quantities they desire to purchase in each hour of the day. Buyers may also

[126] The market power mitigation measures would be developed on a regional basis and would take into account the special characteristics of hydropower.

[127] The operation of both a financially binding day-ahead market in conjunction with a financially binding real-time market is also known as a multi-settlement system.

[128] Such markets are currently operated by the New York ISO and PJM. California ISO and ISO-New England are planning on adding this feature to their market design.

[129] The bids usually take the form of a bid curve that shows the bid price and quantity between the unit's minimum output and its maximum output. Usually the prices are relatively flat over the normal operating range of the unit. As quantities approach the maximum output the prices usually increase very rapidly.

indicate the maximum price they are willing to pay for those quantities.

225. Under the Commission's proposal, buyers are not required to procure energy through the day-ahead energy market. A load-serving entity may procure all of its power through bilateral transactions, in the transmission provider's spot markets, or by generating its own power.[130] However, a load-serving entity may use the day-ahead market if it needs to acquire additional power or the price of power through the day-ahead energy market is lower than the price of power under an existing bilateral contract or the cost of generating its own power. A generator may also buy power through the day-ahead market. It would do this if it could buy the power more cheaply than generating to satisfy a bilateral contract obligation or if a forced outage requires it to procure power to satisfy a contract obligation.

226. The Commission proposes to require Independent Transmission Providers to allow buyers and sellers to submit purely financial bids, a feature that currently exists in the day-ahead markets run by PJM and New York ISO. These financial bids to buy or sell power are not backed by actual generation resources nor are they backed by actual load. Rather, these transactions are used to bring the prices in the day-ahead market and in the real-time market closer together. For example, suppose that the day-ahead price is consistently lower than the corresponding real-time price. Entities may therefore want to submit financial bids to buy energy in the day-ahead market at the lower price, and submit a corresponding bid to sell in the real-time market at the higher price, thereby making a net profit on the two transactions. The additional buyer bids in the day-ahead market would tend to increase day-ahead prices, while the additional supply bids in the real-time market would tend to reduce the real-time prices. The result is that the price differences in the two markets would shrink, as would the profits of sale. This process benefits the market. It helps market participants make better decisions in advance—in the day-ahead time frame—that will affect how much electricity they will sell or buy, because the day-ahead price becomes a more accurate gauge of what the real-time price will be.

227. The day-ahead energy market is operated together with the congestion management system and the day-ahead scheduling process for transmission service. The Independent Transmission Provider will determine market clearing prices for each hour in the day-ahead energy market based on the sale and purchase bids that are submitted. The market clearing price is the bid of the last unit of supply needed to satisfy the demand, *i.e.*, the highest bid that is accepted. The market clearing price at a location is paid to all suppliers at that location that are selected in the auction and is paid by all buyers at that location that purchase through the auction.

228. We believe there are important differences between Standard Market Design and the market design that was in effect in the California ISO when it experienced problems in the energy markets in 2000 and 2001. First, Standard Market Design is premised on the use of bilateral contracts. While LSEs may purchase energy in the spot markets, these purchases should constitute a small percentage of their actual purchases. In contrast, the California market design required the LSEs to purchase the bulk of their energy needs through the spot markets. Second, Standard Market Design includes a forward-looking long-term resource adequacy requirement to avoid the types of supply shortages that adversely affected California. Third, as discussed in more detail in Appendix E, Standard Market Design includes trading rules, a congestion management system, market power mitigation measures, and market power monitoring to address the manipulation strategies encountered in the California markets.

229. In determining market clearing prices, the Independent Transmission Provider factors in the operational limitations of the transmission capacity, such as congestion and reactive power needs, to ensure that the units that set the market clearing prices are consistent with the transmission system operations (*i.e.*, a security-constrained dispatch).[131] Because LMP is used as the congestion management system, the market clearing prices are the prices for energy delivered to each location or node on the system. If there is no congestion on the transmission system, the same market clearing price for energy will apply throughout the system.

230. The day-ahead market would be financially binding. This means that a seller that is selected in the day-ahead market is obligated to actually provide the power in real time or in real time it will be charged the cost of procuring the shortfall through the real-time market.[132] The day-ahead market is also financially binding on buyers.[133] This reduces certain opportunities for strategic bidding and thus, market manipulation.

231. Years of experience with organized markets makes it clear that a day-ahead market is a best practice that must be included in the Standard Market Design. The development of a day-ahead schedule for energy and transmission service, including certain ancillary services, provides reliability benefits. It allows the Independent Transmission Provider to have advance warning to ensure that sufficient units are committed to serve the projected load. For example, if the Independent Transmission Provider believes that load has not scheduled sufficient transmission service or energy purchases in the day-ahead markets, it can commit additional units to be available in real time. Because of their operating characteristics, different types of generation units have differing levels of start-up costs as well as different lead times to be available in real time. The day-ahead market gives the Independent Transmission Provider information on unit availability, costs and system needs well before real time so the Independent Transmission Provider has more options available to ensure reliability and reduce costs in the real-time market.

232. Finally, the day-ahead market provides an important platform for market power mitigation. We propose several mitigation measures to ensure that there is a well-functioning spot market for wholesale power. These spot

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[130] These transactions must still be scheduled through the day-ahead market and are subject to congestion costs if they do not have Congestion Revenue Rights.

[131] It is important that the schedule developed through the day-ahead market be physically feasible, *i.e.*, consistent with reliable transmission limitations. If it were not, then it would be necessary to make separate congestion payments to suppliers in real time to change their output so that the real-time schedule was consistent with reliable transmission limitations. This would provide an incentive for suppliers to create congestion in the day-ahead market so that they could receive payments in real time to relieve congestion.

[132] For example, assume in the day-ahead market a generator agreed to sell 50 MW for the hour running from 9 a.m. to 10 a.m. at a price of $30 Mwh. In the day-ahead market the generator would receive $1,500 ($30 times 50) for that sale. In real time, the generator only delivered 20 MW during that hour. The real-time price of energy in that hour was $40 MWh. The generator would be charged $1200 for its 30 MW shortfall in real time (30 times 40). Thus, the generator would receive a total net payment of $300.

[133] For example, assume that a load-serving entity buys 40 MW in the day-ahead market for the hour 10 a.m. to 11 a.m. at a price of $30 Mwh. In the day-ahead market the load-serving entity would pay $1200 (40 times 30) for that purchase. In real time the load-serving entity only took 35 MW in that hour. The real-time price of energy for that hour was $25. The load-serving entity would effectively sell back the excess power (5 MW) at the real-time price ($25), $125. Thus, the load-serving entity would pay a net total of $1075.

markets will result in price transparency, so buyers and sellers can see that market clearing prices are set in a fair and predictable manner. While the real-time market will be a transparent market, real-time prices may not be known until after the fact or at most five to ten minutes before real time. This gives buyers and sellers little chance to react to prices. In contrast, a day-ahead market provides a transparent spot market that allows buyers and sellers to engage in additional commercial transactions before real time. Thus, a day-ahead market helps liquidity and is likely to be less volatile than the real-time market.

233. The Independent Transmission Provider will also establish hourly prices for certain ancillary services, which may differ by location to the extent that ancillary service requirements differ by location. Since the same supply resources can often be used to provide either energy or ancillary services, energy and ancillary services should have compatible market designs. Otherwise, there would be an incentive to sell one type of product over another. Since both are needed, a compatible system allows the supplier to sell energy or ancillary services, whichever is the most efficient use of the supply resources. This yields the lowest total costs to customers.

234. As explained further below, the Independent Transmission Provider will need to manage congestion in two time frames: (1) During the day-ahead scheduling process, and (2) during real-time operations. The Independent Transmission Provider will conduct separate auctions to manage congestion in each time frame. In the day-ahead auction, for each hour of the following day the Independent Transmission Provider will take bids to buy and sell energy, to provide certain ancillary services, and to purchase transmission service between identified receipt and delivery points. The Independent Transmission Provider will consider the bids for energy, transmission service and ancillary services simultaneously. Based on those bids, the Independent Transmission Provider will develop a schedule that maximizes the economic value (as reflected in the bids) of the transactions over the entire day-ahead period, in light of the amount of Available Transfer Capability and any resulting transmission congestion and losses. The Independent Transmission Provider will also establish prices for transmission service, energy and ancillary services that clear the markets.

3. Congestion Revenue Rights

235. Under LMP, transmission usage prices will vary based on the price of relieving transmission congestion and losses. Rather than using a system of physical reservations, a system of financial rights called Congestion Revenue Rights will be used to give customers the ability to protect themselves against congestion costs.

236. The initial allocation process for Congestion Revenue Rights will be done through compliance filings that allow for different treatment within each region. Since this must occur before Standard Market Design is implemented, we have not addressed initial allocation in the SMD Tariff, but it is discussed in Section IV.E.3.e below. This section describes allocation processes that would be used after the initial allocation has been done.

a. General Features

237. We propose to require that Independent Transmission Providers offer Congestion Revenue Rights of several types (one that we will mandate now and others that should be offered upon customer request when technically feasible) that allow transmission customers to obtain protection against uncertain future congestion charges. We have added a new section to the SMD Tariff that describes the types of Congestion Revenue Rights that would be available, how one acquires Congestion Revenue Rights after the initial allocation and how Congestion Revenue Rights provide protection against congestion costs (Part II.D., Congestion Revenue Rights). The proposed provisions are discussed below.

238. The Independent Transmission Provider would be required to offer Congestion Revenue Rights for all of the transmission transfer capability on the grid, but it would not be allowed to sell more rights than can be accommodated. Congestion Revenue Rights would be available over a variety of terms, such as weekly, monthly, yearly and perhaps for longer terms. If an entity pays to construct new generation or transmission facilities that add transfer capability, and the costs of the upgrade are not rolled in, the entity would receive the Congestion Revenue Rights associated with the new transfer capability. In the past the Commission has allowed credits for upgrades; is there still a role for credits under Standard Market Design?

239. Customers that have not acquired Congestion Revenue Rights in advance could schedule transmission service in the day-ahead market, but they would not have the Congestion Revenue Rights protection against congestion costs.

240. We propose that Congestion Revenue Rights be made available first in the form of receipt point-to-delivery point *obligation rights*, which we propose to mandate now, and later in the form of receipt point-to-delivery point *option rights* and *flowgate rights*.

Currently, in PJM and New York ISO only receipt point-to-delivery point obligations are offered. However, there has been considerable interest expressed by market participants in other types of Congestion Revenue Rights. For example, the Midwest ISO is considering offering a package of Congestion Revenue Rights that are similar to what we are proposing. Also, PJM is considering offering receipt point-to-delivery point options. Offering several different types of Congestion Revenue Rights would make the system more flexible and better able to adapt to the needs of specific customers. Also, certain types of Congestion Revenue Rights may be more valued in different regions of the country based on the physical configuration of the transmission system and the types of resources connected to that system. Various technical papers over the last few years have examined offering these alternate rights simultaneously and concluded that it is feasible under the conditions now specified in the SMD Tariff.[134] Therefore, we believe the tariff should provide this flexibility.

b. Types of Congestion Revenue Rights

241. The SMD Tariff describes the characteristics of each of the types of Congestion Revenue Rights. These descriptions are summarized below.

(1) Receipt Point-to-Delivery Point Rights.

242. A receipt point-to-delivery point right is a right that is specified by a receipt point (which can be a generator node, an aggregation of generator nodes, an interface, a trading hub, or any other collection of nodes) and a delivery point (which can be a delivery node, an aggregation of delivery nodes, an interface, or a trading hub), and the power in MW that is transmitted from the receipt point to the delivery point for a period of time (*e.g.*, one hour).

[134] *See, e.g.*, Hogan, William W., Financial Transmission Rights Formulations, Center of Business and Government, John F. Kennedy School of Government, Harvard University, Cambridge, MA (March 31, 2002); Chao, Hung-Po, Peck, Stephen, Oren, Shmuel, and Wilson, Robert, Flow-based Transmission Rights and Congestion Management, The Electricity Journal, pp. 8, 13 and 38–58 (2000); and Chao, Hung-Po and Peck, Stephen, A Market Mechanism for Electric Power Transmission, Journal of Regulatory Economics (July 1996).

243. A receipt point-to-delivery point right entitles the holder to the day-ahead congestion revenues associated with transmission service from the receipt point to the delivery point.[135] In addition, during any period when the demand for transmission service cannot be met with Available Transfer Capability (*i.e.*, because there are too many customers who have indicated that they want transmission service at any price), holders of receipt point-to-delivery point rights would receive priority over other market participants in scheduling transmission service between the receipt point and delivery points designated in their rights.

244. A receipt point-to-delivery point right would provide the holder with the right to schedule transmission service of the specified amount of power (MW) in the day-ahead market from the receipt point to the delivery point without paying any net charges for congestion (although the holder would need to pay a charge for losses). The reason is that every customer would be entitled to inform the Independent Transmission Provider to schedule its transmission service regardless of the congestion charge. In that case, the customer would be charged for congestion (as well as for losses). But a self-scheduled customer holding a receipt point-to-delivery point right for at least the same amount of power between the same receipt and delivery points would receive congestion revenues that fully offset the congestion charge.

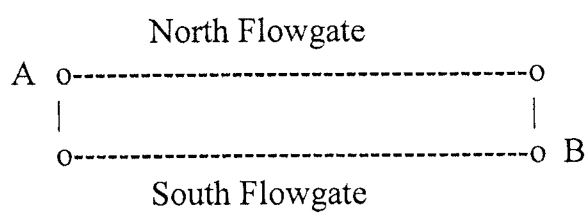
(2) Obligations and Options.

245. Receipt point-to-delivery point rights can take the form of obligations or options. The difference between obligations and options becomes important when congestion occurs in the opposite direction from the right, that is, when there is congestion from the delivery point to the receipt point. In this case, congestion revenues in the direction of the right are negative. Under a receipt point-to-delivery point obligation, the Congestion Revenue Rights holder in that case would be required to pay the negative congestion revenues to the Independent Transmission Provider. Under a receipt point-to-delivery point option, the Congestion Revenue Rights holder would not be required to pay the negative congestion revenues to the Independent Transmission Provider. Existing firm point-to-point transmission contracts under the Order No. 888 *pro forma* tariff do not require contract holders to transmit energy and, thus, are similar to Congestion Revenue Rights that are options.

(3) Flowgate Rights.

246. A flowgate is a particular transmission facility or group of facilities (*e.g.*, an interface). A flowgate right specifies a portion of the transmission capacity over that flowgate in a specified direction. A flowgate right entitles the holder to the day-ahead congestion revenues associated with the specified power flows over the flowgate in the specified direction.

246a. Consider, for example, a very simplified transmission network that connects two points, A and B, with two different but interconnected transmission lines, a northern line and a southern line, as shown below:



Each transmission line could be a separate transmission or flowgate, and separate flowgate rights could be issued for each line. The holder of a flowgate right on the northern line from west to east would be entitled to the congestion revenues associated with that line in the west-to-east direction. However, holding a flowgate right on the northern line would not entitle the holder to congestion revenues associated with the southern line. Hence, if transmission service results in energy flows over several flowgates, the buyer must obtain sufficient rights on each flowgate to obtain protection from congestion charges. By contrast, the holder of a receipt point-to-delivery point right from west-to-east (*i.e.,* from A to B) would be entitled to congestion revenues in the west-to-east direction regardless of whether the northern or the southern lines were congested and thus would have a complete hedge for this transaction.

246b. Unlike a receipt point-to-delivery point obligation, a flowgate right would never require the holder to make congestion payments. The congestion revenue associated with a flowgate in a specified direction would equal the additional net economic value to market participants that would result by incrementally increasing the flowgate's capacity in the specified direction. That additional net economic value may be either positive (*i.e.*, when the flowgate is congested) or zero (*i.e.*, when the flowgate is not congested), but it would never be negative.

247. Receipt-point-to-delivery-point rights offer the transmission customer with long-term energy contracts the best way to protect itself against hourly congestion costs. However, many transmission customers may be meeting their loads' needs with a portfolio of generators scattered around a regional electricity market. Such customers may be seeking a more flexible type of right than the receipt-point-to-delivery point right (which is typically only reconfigured on a monthly basis and which can be traded on the secondary market most easily if another customer requires the same points as specified in the right). The major market advantage of the flowgate right is that since there are fewer congested flowgates than possible under receipt-point-to-delivery-point rights, transmission customers can focus their rights on the key congested flowgates. This allows for coverage of much of the congestion charges (in some estimates, between 80 percent to 90 percent). However, the flowgate rights may not provide a complete protection against congestion charges for a receipt point-to-delivery point energy transaction, since the congestion revenues may differ from the congestion charges.

[135] The right is direction-specific. The holder is entitled to congestion revenues from the receipt to delivery point, not from the delivery point to the receipt point.

c. Requirement for Offering Rights

248. At the start of Network Access Service, the Independent Transmission Provider would be required to offer receipt point-to-delivery point obligations. These rights are the easiest to implement because they are already in wide use. While we want the market to develop additional choices for customers, we are concerned about requiring implementation of numerous types of rights, including types of Congestion Revenue Rights that have not yet been tested by an ISO or RTO, when Standard Market Design is first implemented. Because there is no experience with the other types of rights, we propose not to require the Independent Transmission Provider to offer them initially. However, upon the request of market participants, the Independent Transmission Provider would be required to offer receipt point-to-delivery point options and flowgate rights as soon as technically feasible.

249. Additionally, Congestion Revenue Rights could be offered for various terms, *e.g.*, one month or five years. Some customers may desire Congestion Revenue Rights with multi-year terms to correspond to the terms of long-term power contracts, including contracts used to satisfy the resource adequacy requirement discussed in Section J. At the same time, it may be difficult for the market to value long-term Congestion Revenue Rights until a region has actual operating experience under an LMP congestion management system. This could create problems in an area that auctions all Congestion Revenue Rights and allocates the auction revenue rights to load. We seek comment on whether the Commission should require the Independent Transmission Provider to offer multi-year Congestion Revenue Rights when Standard Market Design is first implemented. Additionally, we seek comment on whether the Independent Transmission Provider should be required to offer Congestion Revenue Rights with terms tied to the planning horizon used in the region to satisfy the resource adequacy requirement.

d. Funding for the Congestion Revenue Rights

250. As explained above, holders of Congestion Revenue Rights would be entitled to receive congestion revenues associated with transmission congestion in each hour of the day-ahead market. The aggregate amount of Congestion Revenue Rights issued by the Independent Transmission Provider would be the amount simultaneously feasible based on Available Transfer Capability under normal operating conditions. As a result, during normal operating conditions, the Independent Transmission Provider would collect enough congestion charge revenue from users of transmission service in the day-ahead market to fully pay the day-ahead congestion revenues owed to holders of Congestion Revenue Rights. Indeed, the Independent Transmission Provider might collect a surplus of revenue in some hours during normal operating conditions. However, when a significant amount of transmission facilities are out of service, so that less transmission service can be provided, the Independent Transmission Provider may collect less congestion charge revenue from transmission users than the amounts owed to Congestion Revenue Rights holders.

251. There are two ways to handle this revenue shortfall. First, the amount of congestion revenues paid to the holders of Congestion Revenue Rights may have to be reduced. As a result, the customer may only be able to protect against a portion (*e.g.*, 95 percent) of its congestion costs in the day-ahead market. Alternatively, the customer that has a Congestion Revenue Right could receive full protection against congestion costs and the revenue shortfall would be assigned to the transmission owner. We propose to use the latter approach. When such revenue deficits arise, we propose that such deficits be made up by transmission owners whose transmission facilities are out of service. We would, however, include an exception for outages due to force majeure events, since our intent is to reward transmission owners for proactively maintaining their transmission facilities.[138,137] Assigning revenue deficits in this way would encourage transmission owners to take steps to minimize forced transmission outages and to schedule maintenance outages so as to minimize their effect on congestion costs. Assigning congestion revenue surpluses to transmission owners may also encourage them to minimize outages. However, such a policy may also create an interest on the part of transmission owners in maintaining congestion, and thus may discourage them from building needed transmission expansions. We propose that any revenue surpluses be paid to transmission owners, but we seek comment on the potential of this policy to discourage transmission expansions and if alternative mechanisms should be used to distribute the revenue surpluses.

e. Auctions and Resales of Congestion Revenue Rights

252. We believe it is important that there be an active secondary market for Congestion Revenue Rights. This will allow a market mechanism for customers that have Congestion Revenue Rights to acquire new ones or to sell Congestion Revenue Rights they no longer need. Additionally, this provides a way for market participants that do not have Congestion Revenue Rights to acquire them. Market participants would be allowed to resell any Congestion Revenue Rights that they have been awarded for the full term of the rights or for a part of the term. Resales could be transacted bilaterally between willing buyers and sellers. In addition, we propose to require that the Independent Transmission Provider conduct periodic auctions of Congestion Revenue Rights. The Independent Transmission Provider's auction would allow holders of rights to resell their Congestion Revenue Rights in an organized market. This would provide greater price transparency for these rights than if all sales were conducted through bilateral transactions. Moreover, the auctions would provide the ability to reconfigure Congestion Revenue Rights into different receipt and delivery points, or into different types of rights (*e.g.*, receipt point-to-delivery point options, obligations, or flowgate rights). This would allow Congestion Revenue Rights holders to change their Congestion Revenue Rights if for example they decided to switch suppliers. The auctions would also allow Congestion Revenue Rights associated with other transmission capacity that becomes available (such as through the expiration of previously issued Congestion Revenue Rights) to be sold.

253. In the auctions, buyers and sellers would submit bids that specify the type of Congestion Revenue Rights desired to be bought or sold, the location, term and price. The Independent Transmission Provider would select the combination of bids that maximizes the economic value of the transactions for the participants. In so doing, the Independent Transmission Provider must reconfigure the Congestion Revenue Rights offered for sale in a way that maintains the simultaneous feasibility of the Congestion Revenue Rights. That is, the types and/or locations of the Congestion Revenue Rights offered for sale may differ from those that are purchased. The Independent Transmission Provider

[136,137] As a result, in the event of force majeure the Congestion Revenue Rights would not be fully funded.

would establish market-clearing prices for each Congestion Revenue Right bought or sold. Each seller would receive the market-clearing price for the rights that it sold, and each buyer would pay the market-clearing price for the rights that it purchased.

f. Including Energy and Ancillary Services in the Congestion Revenue Rights Auctions

254. The time period covered by the Congestion Revenue Rights sold in auctions would be a month or longer. We propose that an Independent Transmission Provider would be permitted, but not required, to conduct pre-day-ahead auctions for energy and ancillary services. Under such auctions, market participants could offer to buy and sell energy and ancillary services at specific locations on a forward basis for a specified time period, such as for a month or a year. Participation in these pre-day ahead markets, as in all markets, would be on a voluntary basis. Such purchases and sales of energy and ancillary service would require use of the transmission system, just as sales of Congestion Revenue Rights would. Thus, in conducting pre-day-ahead auctions, the Independent Transmission Provider would allocate transmission capacity among competing demands for Congestion Revenue Rights, forward energy and forward ancillary services so as to maximize the economic value of the winning bids. The Independent Transmission Provider would establish market-clearing prices for forward energy and ancillary services at each location, as well as market-clearing prices for Congestion Revenue Rights.

255. A potential benefit of pre-day-ahead auctions is that they could more easily maximize the economic benefits of transmission capability by considering a greater array of competing uses of the transmission grid. They could also provide a convenient, central market forum for buyers and sellers to arrange forward trades of energy and ancillary services. They could provide transparency and liquidity (and thus protection against manipulation) in long-term markets where liquidity has recently been reduced.

F. Day-Ahead and Real-Time Market Services

256. This section sets forth the bidding, scheduling, price determination, and settlement provisions necessary to implement LMP in the day-ahead and real-time markets for energy, regulation and both operating reserves. In this section, we lay out the basic elements that would be used for congestion management and operation of the spot markets.[138]

1. Design of the Day-Ahead Markets

257. We propose that the Independent Transmission Provider operate day-ahead and real-time markets for energy and certain ancillary services in conjunction with its scheduling of transmission service day ahead and in real time. These markets would allocate transmission and generation capacity among competing uses in different markets through LMP pricing. For example, the markets would determine how much transmission capacity would be allocated for transmission service to market participants completing bilateral energy transactions, for use by the Independent Transmission Provider in completing energy sales and purchases through its bid-based energy markets, and for providing ancillary services. The markets should be operated jointly to ensure that transmission and generation capacity is allocated where it is most valuable, and to ensure that the prices for the products and services are internally consistent.

a. Scheduling Transmission Service Day Ahead

(1) General Features.

258. Each day the Independent Transmission Provider would accept requests to schedule transmission service to support bilateral energy transactions or customer-owned generation for each hour of the following day. A customer desiring transmission service would be required to submit a scheduling request in a standardized form specified by the Independent Transmission Provider. For each requested transmission service, the scheduling request would indicate the receipt point and the delivery point of the bilateral energy transaction or customer-owned generation, the amount of power (MW) to be transmitted and the time period. To facilitate the ability of demand to respond to price signals, transmission customers will be given several ways of indicating their willingness to change their consumption based on congestion costs and marginal losses: (1) Customers (whether or not they hold Congestion Revenue Rights) would be allowed to specify in their scheduling requests the maximum transmission usage charge (reflecting the costs of congestion and marginal losses) at which the customer desires service;[139] (2) customers would be allowed to specify the maximum congestion charge component of the transmission usage charge at which they desire transmission service, or above which they are unwilling to pay any congestion costs; or (3) customers (whether or not they hold Congestion Revenue Rights) could submit a bid that states a desire for transmission service to be scheduled regardless of the transmission usage charge. This option may be useful for a holder of a Congestion Revenue Right that desires to schedule transmission service that uses the receipt point-to-delivery point combination covered by that Congestion Revenue Right.

259. Another way that transmission customers will be able to respond to price signals is by submitting multi-hour block bids, requesting transmission service for a block of consecutive hours and indicating the maximum price for the entire multi-hour period. For example, a multi-hour block bid might specify that the customer desires 10 MW of transmission service from receipt point A to delivery point B in each hour from 1 p.m. to 6 p.m. as long as the price per MW for the entire 5-hour period does not exceed $10. Such a bid would be accepted if the sum of the hourly transmission usage prices for each of the 5 hours did not exceed $10. Otherwise, the entire bid would be rejected. This option allows a customer, for example an industrial customer in a state with retail access, to indicate that it is willing to reduce its transmission usage if the prices for a multi-hour period are above a specified level. This feature has not been put in practice in any of the bid-based markets operated by ISOs. We seek comments on its merit and any implementation difficulties.

260. The Independent Transmission Provider would consider these transmission scheduling requests in conjunction with bids submitted in its day-ahead energy and ancillary service markets. Based on all of these, the Independent Transmission Provider would accept the set of energy bids and scheduling requests and develop a day-ahead schedule that maximizes the economic value for all market participants. The Independent Transmission Provider would also

[138] Part I of the SMD Tariff includes a definition of the terms related to market services. In addition, as we use the term "supplier" or "seller" in this Section, the definition we are using includes both generators and demand-side resources that satisfy the Independent Transmission Provider's applicable requirements.

[139] For example, when transmission usage prices become sufficiently high, customers holding receipt point-to-delivery point Congestion Revenue Rights may prefer not to schedule transmission service between their designated receipt and delivery points. Instead, the customers may prefer to receive the applicable congestion revenues. Customers could communicate these preferences through price-bids.

establish transmission usage prices for each hour of the next day that are the same as the implicit transmission usage price included in the set of locational energy prices (*i.e.*, the difference in the price of energy at the receipt point and at the delivery point, which reflects both congestion and losses).

261. The Independent Transmission Provider would schedule all requests for transmission service since these users have agreed to pay any applicable congestion charges. The Independent Transmission Provider would also schedule all requested transactions where the transmission usage charge was below the amount the customer indicated it was willing to pay.

262. Customers with Congestion Revenue Rights would receive congestion revenues that help offset any congestion charges paid as part of the transmission usage charge. The amount of the congestion revenues received (and the associated protection against congestion charges) would depend on the specific Congestion Revenue Rights held. A customer holding receipt point-to-delivery point Congestion Revenue Rights for a certain amount of power between a delivery and receipt point that matches its day-ahead transmission schedule would receive congestion revenues that exactly offset its congestion charges, so that its net bill would reflect no congestion charges (although it would be charged for losses).

263. The above process would be used for scheduling transmission service on a daily basis. Some customers, particularly those with Congestion Revenue Rights, may desire to schedule the same exact service over a longer period to save on administrative costs. The Commission seeks comments on whether a customer should be allowed to provide a schedule for multiple days or have a standing scheduling request that would remain in effect until changed by the customer. Any schedule request, once scheduled by the Independent Transmission Provider would become financially binding on the customer at the close of each day's day-ahead market.

(2) Transmission Service Across Borders.

264. Transmission service across the border of adjoining Independent Transmission Providers' service areas—from a point of receipt in one service area to a point of delivery in another—requires coordination between the affected Independent Transmission Providers. When transmission congestion exists between a point of receipt and a point of delivery in different service areas, managing the congestion becomes more difficult because more than one Independent Transmission Provider is involved.

265. There are at least two methods for arranging for transmission service across borders—physical reservations (*i.e.*, continuing firm point-to-point reservations of transfer capability), and scheduling of service consistent with internal transactions under Network Access Service (scheduling of transmission and financial bidding). We propose to treat transmission service across borders in the same way as internal transactions. Thus, like internal transactions, an importing or exporting customer could either schedule transmission service and agree to pay the transmission usage charge regardless of the level or submit a bid that limits its congestion exposure. Under the first method, the transmission customer would submit to each Independent Transmission Provider a request to be scheduled for transmission service to and from the border, regardless of the applicable transmission usage charges that it will be assessed. The customer would be scheduled unless congestion arose that could not be relieved through redispatch or some other means. Under the second method, financial bidding, the customer would submit a price bid to each Independent Transmission Provider indicating the maximum transmission usage charge that it is willing to pay for transmission service on each side of the border. The customer would be scheduled if its price bid on each side of the border was at or above the applicable transmission usage charge. Under either method, if the customer's transaction is scheduled, the customer would pay the applicable transmission usage charges to and from the border. We propose to make both options available to transmission customers, because each option may provide benefits to customers. We would prefer ''one-stop shopping'' with Independent Transmission Provider coordination; we seek comment on whether this can be done?

266. Recently we accepted a prescheduling option for service across borders that was proposed by the New York ISO.[140] A prescheduling option would give a customer certainty prior to the day-ahead market that it could transmit power across a border. Under the New York ISO's prescheduling option a customer may schedule such a transaction up to eighteen months in advance of the dispatch day. A customer that requests a prescheduled transaction agrees to pay the applicable market clearing transmission usage charge. Once submitted, the transaction would be financially binding unless the New York ISO permits the customer to withdraw the prescheduled transaction. We seek comment on whether a similar prescheduling option should be included in Standard Market Design.

[140] New York Independent System Operator, Inc., 99 FERC ¶ 61,292 (2002).

b. Transmission Losses

267. When energy is transmitted from a point of receipt to a point of delivery, some of the energy is lost due to resistance on the wires. These transmission losses are a cost of transmission and commonly are recovered on an average cost basis from all transmission customers. As noted earlier, we are proposing that energy prices and the associated transmission usage charges be based on marginal costs, in order to promote economic efficiency. We seek comment on whether transmission losses should be recovered on the basis of the marginal cost of losses or if they should be recovered on the average cost of losses. There are advantages and disadvantages to each approach. Using marginal losses would promote a more efficient use of the transmission system. However, as discussed below, charging marginal losses will collect surplus revenues that must then be returned to transmission customers. On the other hand, the advantage of charging average losses is simplicity. If average losses are charged, the losses collected from customers would equal actual losses. There would be no need to create a mechanism to return surplus losses.

268. For customers purchasing transmission service to complete bilateral transactions, we see value in allowing transmission customers to pay for their assigned losses either in cash or in kind. To pay in cash, the customer would pay the market price for its assigned MWhs of losses, which would be included in the applicable transmission usage charge. Thus, the MWh of energy injected at the point of receipt would equal the MWh withdrawn at the point of delivery. The transmission provider would procure the energy used for losses from its energy market. To pay in kind, the customer would supply energy at the point of receipt in the amount of its assigned losses. Thus, the MWhs injected at the point of receipt would exceed the MWhs at the point of delivery by the amount of the assigned losses, and the customer would pay in cash only the congestion component of

the transmission usage charge.[141] We note, however, that some commenters in our outreach process expressed concern that allowing customers to provide losses in kind may unduly complicate the scheduling process, especially for transactions that involve multiple Independent Transmission Providers. We seek comment on whether transmission customers should have the choice of paying for losses in cash or in kind, or alternatively, whether all transmission customers should be required to pay for losses in cash.

c. Day-Ahead Energy Market

(1) General Features.

269. We propose that the Independent Transmission Provider be required to run a voluntary, bid-based, security-constrained day-ahead energy market. ''Voluntary'' means that market participants do not have to buy or sell in the day-ahead energy market. The day-ahead market we are proposing provides customers with additional supply choices. It is not intended to substitute for other longer-term arrangements that customers may use to purchase supplies such as bilateral transactions or use of a customer's own generation. Thus, market participants would be able to schedule bilateral transactions and/or their own generation rather than bid into the day-ahead energy market. ''Bid-based'' means that participants may submit offers to buy or sell quantities of energy into the market and may specify the prices at which they are willing to transact. This provides an organized and transparent system for the Independent Transmission Provider to determine the marginal cost of relieving transmission congestion. ''Security-constrained'' means that the Independent Transmission Provider, in the energy auction process, takes account of all system constraints, such as contingency limits, needed for reliable system operations and develops a schedule that does not violate such constraints. This is necessary to ensure that the day-ahead schedule is physically feasible. Otherwise, the Independent Transmission Provider might be required to make additional payments in real time to relieve congestion, which could provide an incentive for market participants to create congestion in the day-ahead market to receive these payments in the real-time market.[142] The market should allow full participation by both the supply side and the demand side of the market.

(2) Bidding and Scheduling Rules.

270. Each day, the Independent Transmission Provider would accept bids to sell and buy energy for each hour of the following day. Participants desiring to sell or buy energy would submit a bid in a standardized form.

271. Each seller's bid would indicate the amount of power (MW) offered to be sold, the receipt point, and the time period. In addition, each seller would be allowed to submit multi-part bids that separately specify bid prices for start-up, no-load, and energy, as well as technical characteristics such as ramp rates, minimum run times and minimum down times. Allowing suppliers' bids to include these items yields more detailed information that can improve the ability of the grid operator to dispatch suppliers with the lowest total cost. For example, if the supplier were required to submit a one-part bid it would need to include start-up costs in its energy bid, resulting in a higher energy price bid. However, a supplier submitting a bid that separately specified the energy bid and the start-up costs would not have to make these estimates and the grid operator would use the bids to dispatch the supplier with the lowest total cost. Suppliers would also be allowed to submit bids that are self-schedules, that is, that would indicate an amount to be supplied at a location regardless of the applicable energy price. The supplier would receive the applicable market clearing price for its energy. This option may be useful for suppliers with very high start-up costs such as nuclear facilities. Intermittent resources would be able to participate in the day-ahead market on the same basis as other resources.

272. Similarly, each buyer's bid would indicate the desired amount of power (MW) to be bought, the delivery point, and the time period. In addition, each buyer would be allowed to specify bid prices that indicate the quantities it is willing to purchase at alternative prices. Buyers would also be allowed to submit multi-part bids that indicate the time and price constraints under which they are willing to purchase energy. These options would facilitate demand response programs because they allow the buyer to indicate the price at which it will voluntarily reduce its consumption. Buyers would also be allowed to schedule an amount to be purchased regardless of the applicable energy price.[143] Bids would not need to be tied to a physical generator or load resource. However, for reliability purposes, bids would need to indicate whether they were purely financial bids or whether they were tied to a physical resource. This would permit market participants to bring day-ahead and real-time prices closer together, increasing the stability of both markets. This option should reduce price differences between these two markets.

273. Buyers and sellers would be able to submit different price bids for different hours of the day, and bids could vary from day to day. However, if market participants can exercise market power, limits may be imposed on bidding to mitigate market power, as discussed below in the section addressing market power monitoring and mitigation.

274. We propose a scheduling option to address the special conditions facing energy-limited resources such as hydroelectric and environmentally constrained thermal resources. These resources are limited in the amount of energy or the number of hours that they can produce energy over a period of time. As a result, production in one hour may reduce the amount of energy that the resource can produce (and the associated revenue) in other hours. Energy-limited suppliers could submit bids in the day-ahead market that specify the amount of energy, or the number of hours, available for production over the next day. The supplier could then request the Independent Transmission Provider to schedule its energy in those hours of the next day when the energy price is highest. Such a scheduling feature would promote efficient scheduling because it would allow the energy-limited resource to be scheduled where its energy would have the greatest value, with maximum profit to the resource owner.[144] We recognize that the

[141] The amount of energy needed for losses would not be known until the close of the market. For transactions in the day-ahead market, the Transmission Provider would inform each customer that wishes to supply losses in kind (after the close of the day-ahead market) of the amount of its assigned losses (in MWh), and that amount would be included in the customer's day-ahead schedule. For transactions in the real-time market, the Transmission Provider could provide an estimate in advance of the amount of each customer's assigned losses. However, since actual marginal losses would not be known until after the fact, the customer would be charged or credited at the applicable LMP for any under- or over-provision of losses.

[142] *See* the discussion of this issue in Appendix E.

[143] Since energy prices have the potential to rise to very high levels, it may be necessary to require buyers that request energy without submitting a price bid to demonstrate to the Independent Transmission Provider in advance that they are financially capable of paying very high prices for such quantities. Alternatively, the Independent Transmission Provider could limit the amounts based on a buyer's creditworthiness.

[144] While this scheduling feature is intended mainly for energy-limited resources, it would be available to all generators and would not be restricted to energy-limited resources, unless such restrictions are necessary to mitigate market power.

resource mix varies significantly from region to region and that some regions, such as the Northwest, have a greater amount of energy limited resources. We seek comment on whether other scheduling options or regional variations should be included for energy-limited resources in the tariff.

275. We recognize that intermittent resources such as wind power may also benefit from scheduling rules that recognize their inability to precisely control output. We recently approved a special mechanism for intermittent resources selling into the energy market run by the California ISO.[145] Under that mechanism, the intermittent resource and the California ISO work together to develop a schedule and procedures for accurately forecasting the output of the resources. However, California ISO currently runs only a real-time market for energy and not both a day-ahead market and real-time market as proposed here. Also, the amount of power produced by intermittent resources within California is much larger than in many parts of the country. We propose to include the California ISO's scheduling option for intermittent resources as part of Standard Market Design. However, we seek comment on whether there is a better way to schedule intermittent resources.

276. Finally, in drafting the bidding and scheduling rules we have included several ways for demand to respond to prices. We recognize that several ISOs currently have demand response programs that operate differently. Under these demand response programs, the ISO pays end-users to reduce their demand if market clearing prices reach a certain level. We believe the direct approach of letting demand bid in the market will be less costly than a program where an end-user receives payments greater than the market clearing price to reduce its demand. We have not proposed to include these types of programs in the *pro forma* tariff although they could be included if the Independent Transmission Provider, in consultation with the state advisory committee and stakeholders, determined that they were necessary. Since the participation of demand in the market is critical for an effective wholesale market, we seek comment on whether the measures proposed are sufficient or if other measures should be included.

(3) Price Determination and Settlement.

277. Based on the accepted bids included in the day-ahead schedule, the Independent Transmission Provider would establish day-ahead locational energy prices for each hour. The hourly energy price at each location would reflect the marginal cost (as reflected in bids) of producing and delivering energy to that location in that hour. Energy prices would be consistent with the transmission usage charges, so the difference in energy prices between two locations in an hour would reflect the cost of transmitting energy from one location to the other.

278. The Independent Transmission Provider would establish a single market-clearing energy price for each hour for each node on its transmission system. We believe it is important that energy prices be calculated for each node to avoid socialization of congestion costs and to reduce the possibility of manipulating the congestion management system.[146] The Independent Transmission Provider could also establish nodal prices for time intervals shorter than an hour. Nodal pricing would be used for both buyers and sellers in the day-ahead market.

279. Upon request of market participants, the Independent Transmission Provider would establish trading hubs. A trading hub is a virtual location where financial transactions may be arranged, whose hub price is the weighted average of energy prices at a specified set of nodes on the transmission system. A trading hub facilitates financial trading and aggregation of supplies from multiple sources. Creation of trading hubs should not lead to socialization of congestion costs, because the price for service at the trading hub is the weighted average of prices at the various nodes that are included in the trading hub. Energy may not be injected or withdrawn from the grid at a trading hub, since a hub does not exist at a physical location. But a hub may be named as an intermediate point between physical points of injection and withdrawal where financial energy trades may occur.[147] Also, at the request of market participants, the Independent Transmission Provider would establish zones that are the weighted average of energy prices at selected delivery nodes on the transmission system. This option would permit a load-serving entity to aggregate prices for deliveries to its various delivery nodes.

280. Each buyer and seller would transact at the applicable clearing price for the hour and time period. A seller that submits separate bids for start-up and no-load costs and is dispatched by the Independent Transmission Provider for any period during the day, will be assured that it will recover the start-up and no-load costs that it bid. If a seller's total bid costs (including start-up and no-load costs, as well as energy running costs) over the entire day are not fully covered by its revenues from selling at the hourly clearing prices, it would receive an additional payment (*i.e.*, an ''uplift'' payment) for the net revenue shortfall for the day. Hourly energy prices would be based only on energy bids; start-up cost bids and no-load bids would not be used in calculating hourly energy prices. Thus, a generator may have legitimate start-up costs that are not fully covered by selling at the hourly energy price over the day; paying uplift may be necessary to ensure that generators selected in the auction will receive revenues that fully cover their bid-costs.[148] Since the additional payments are a cost of providing supplies of energy and ancillary services in the Independent Transmission Provider's day-ahead market, we propose to recover the additional payments from entities that purchase energy and/or ancillary services in the Independent Transmission's Provider's day-ahead market. Any entity that does not buy any energy from the Independent Transmission Provider's day-ahead market on a given day, and that self-supplies all of its ancillary service obligations on that day, would

[145] *See* California Independent Operator Corp., 98 FERC ¶ 61,327, *order accepting compliance filing*, 99 FERC ¶ 61,309 (2002).

[146] *See* discussion in Appendix E of manipulation strategies involving congestion management.

[147] A good example of a trading hub is PJM's Western hub, where there are active spot energy and transmission rights markets, as well as bilateral markets.

[148] For example, suppose that the Independent Transmission Provider needs to supply an additional 100 MW load in each of 20 hours over the next day. Two generators, A and B, are available. Generator A has energy costs of $35/MWh, but must incur $15,000 in start-up costs before beginning production. Generator B has energy costs of $40/MWh, and has no start-up costs. Generator A's total cost of meeting the load would be $85,000 (*i.e.*, total energy costs of $70,000 [$35/MWh × 100 MWh × 20 hrs] PLUS start-up costs of $15,000). Generator B's total cost would be $80,000, comprised exclusively of energy costs (*i.e.*, $40/MWh × 100 MWh × 20 hrs). Generator B should be chosen because its total costs ($80,000) would be less than Generator A's total costs ($85,000). Suppose that the hourly clearing price in each hour is $42/MWh. By selling 100 MWh in each of 20 hours, Generator B would receive total revenues of $64,000 (*i.e.*, $32/MWh × 100 MWh × 20 hrs), which is $6,000 less than its total bid-in costs of $70,000. Generator A would thus need to receive a $6,000 uplift payment in addition to its energy revenues. Paying $6,000 in uplift is still cheaper for customers than the alternative of dispatching Generator B.

not be assigned a share of the additional payment for that day.

281. The results of the day-ahead market would be financially binding on buyers and sellers. That is, sellers would be paid the applicable locational day-ahead price for energy scheduled to be sold in the day-ahead market, and buyers would pay the applicable locational day-ahead price for energy scheduled to be bought in the day-ahead market. In addition, to the extent sellers and buyers fail to actually produce or take energy according to their respective schedules in real time, such imbalances would be settled at the applicable real-time energy price. Thus, a seller would pay the real-time LMP nodal price for any scheduled energy that it fails to deliver in real time to its bid delivery point. Similarly, a buyer would be paid the applicable LMP nodal real-time price for any scheduled energy that it does not take at its bid receipt point in real time.

282. The Independent Transmission Provider would post prices and other market information and settle the markets promptly to provide market participants with reliable information regarding their market transactions.

283. In certain instances, a generator may alleviate a voltage or stability constraint by producing real power and/or reactive power at its location. By alleviating the constraint, the transfer capability of the grid may be increased, thereby allowing a greater amount of lower-cost energy to be transmitted to an area with higher energy prices. For example, the transmission capability to import power into a load pocket may initially be limited to 1000 MW due to a voltage or stability constraint, even though the thermal limit is 1500 MW. However, production of an additional 100 MW of real power and/or an additional amount of reactive power within the load pocket could increase import capability into the load pocket by 50 MW, to 1050 MW. We seek comment on whether generators who provide such real or reactive power should receive additional compensation (in addition to the locational market price for energy and the applicable compensation for reactive power) for the additional transfer capability that they create, to provide incentives to produce energy that increases transfer capability. For example, should such generators be given the Congestion Revenue Rights with the additional transfer capability that they create? In certain circumstances, a generator must reduce its production of real power in order to increase its production of reactive power. In these circumstances, should the generator be compensated for the opportunity cost of its reduced profits from selling real power? Should the generator be paid the higher of its opportunity costs or the market congestion value of the additional transfer capability created? How should locational market power concerns be addressed in these circumstances?

d. Day-Ahead Ancillary Service Markets

(1) General Features.

284. Order No. 888 identified six ancillary services. Under this proposed rule, all six ancillary services must be provided by the Independent Transmission Provider, but the three listed below need not be obtained from the Independent Transmission Provider:[149]

(1) Regulation and frequency response
(2) Operating reserve—spinning
(3) Operating reserve—supplemental

Transmission customers may meet their responsibility through self-supply, by procuring these ancillary services from a third party, or by acquiring them from the Independent Transmission Provider.

285. As discussed earlier, imbalance energy would be provided through the day-ahead and real-time energy markets. For the remaining three ancillary services (regulation and both operating reserves), we propose to require that the Independent Transmission Providers operate bid-based markets open to all potential suppliers so that Independent Transmission Providers can procure these ancillary services from the lowest cost suppliers. Different regional reliability authorities may establish different requirements for operating reserve—supplemental. For example, the four jurisdictional operating ISOs procure resources for the ancillary service operating reserve—supplemental (which are usually generation resources that are not synchronized with the grid or demand-side resources that can curtail use), with varying response times. Each ISO procures a portion of their necessary operating reserve—supplemental requirement with reserves that can respond within 10 minutes of a dispatch request, as well as slower-responding reserves at 30 minutes (New York ISO and ISO-New England) and 60 minutes (California). Since different regional reliability authorities have established different response times for operating reserve—supplemental, we do not propose a standard set of markets for operating reserve—supplemental. However, we propose to require that each Independent Transmission Provider operate separate markets for each type of operating reserve—supplemental that it procures.

286. Location-specific reserve targets may be required in some areas due to persistent and significant congestion. The Independent Transmission Provider would identify and establish these targets consistent with any reliability rules.

(2) Bidding and Scheduling Rules.

287. Each day, the Independent Transmission Provider would determine the total amount of each of the ancillary services that will be required for each hour of the following day. Customers that wish to meet their ancillary service requirement through self-supply or procurement through a third party would be required to provide the Independent Transmission Provider with the necessary information about the generation capacity or demand-side resource that would be providing the ancillary services (as is currently required under the existing *pro forma* tariff).

288. To procure the remaining amount of ancillary services, the Independent Transmission Provider would accept bids for regulation and the types of operating reserves for each hour of the following day. A participant desiring to sell regulation or operating reserves would submit a bid in a standardized form specified by the Independent Transmission Provider. Bids could be offered to provide ancillary services from generation capacity or any demand-side resource that meets the technical requirements of the ancillary service. Participants could offer the same capacity in more than one ancillary service market, as well as in the energy market.

289. Each bid would indicate the type of ancillary service, the amount of generating capacity (MW) offered for sale, the receipt point of the resource and the time period. The bid would also include an availability bid indicating the minimum price per MW (which could be either a positive amount or zero) required to provide the ancillary service. The availability bid would allow the bidder to ensure that it would not be selected to provide the ancillary service unless the ancillary service price is high enough to cover out-of-pocket costs, such as the costs of keeping a crew at its facility for the following day. The bid would also include the various components that would be submitted to

[149] The remaining ancillary services that must be obtained from the Independent Transmission Provider are (1) Scheduling, System Control and Dispatch Services, (2) Reactive Supply and Voltage Control Service, and (3) Energy Imbalance Service. We seek comment on treating Scheduling, System Control and Dispatch Services as a basic cost of providing transmission service instead of as an ancillary service.

provide energy into the energy market. These components include an energy bid, indicating the minimum price per MWh required to produce energy. Other bid components would include price-bids for start-up and no-load, as well as technical constraints, such as minimum load, ramp rates, minimum run time and minimum down time. By providing one ancillary service, a bidder may forgo profits from sales in other markets, and these forgone profits are an opportunity cost of providing ancillary services. As explained in the following section, the Independent Transmission Provider will consider the opportunity cost associated with forgone sales in other markets operated by the Independent Transmission Provider. Opportunity costs from forgone sales in markets not operated by the Independent Transmission Provider could be included in the bidder's availability bid.

290. The Independent Transmission Provider would consider all bids to sell ancillary services, in conjunction with bids submitted in its day-ahead markets for energy and transmission service. As noted earlier, based on all submitted bids, the Independent Transmission Provider would maximize the economic value (as reflected in the bids) of the accepted bids, *i.e.*, accept the bids with the overall lowest cost. Thus, for generation capacity and demand-side resource that bid into more than one market, the Independent Transmission Provider would schedule the generation capacity or demand-side resource into the market where it is most efficient (unless it is not efficient to schedule the generation capacity or demand-side resource in any market).[150] This should yield the overall lowest cost for procuring energy, regulation and operating reserves.

(3) Price Determination and Settlement.

291. Based on the accepted bids included in the day-ahead schedule, the Independent Transmission Provider would establish day-ahead prices for each of the ancillary services procured in the bid-based markets for each hour. In regions with separate locational ancillary service requirements, the Independent Transmission Provider would establish separate hourly locational ancillary services prices.

292. To promote an efficient market, the price for regulation and operating reserves services would equal the marginal cost of each service, which would equal the highest accepted total bid cost expressed in dollars per MW. The total bid cost of each generator is the sum of: (1) The generator's availability bid per MW and (2) the opportunity cost of forgoing sales in other markets operated by the Independent Transmission Provider, expressed on a per-MW basis.[151]

293. A generator or demand-side resource could be eligible to bid into more than one market operated by the Independent Transmission Provider. The opportunity costs paid to the supplier would be the forgone profit from the most profitable other market. For example, a generator that is capable of providing ancillary services could also sell into the transmission provider's day-ahead energy market, although it would incur additional variable energy costs to do so. Thus, the forgone profit from selling into the energy market (as reflected in the generator's bid) would be the difference between the energy price and the generator's energy bid. The opportunity cost of selling ancillary services would include this forgone energy profit.

294. The hourly price for one of these ancillary services in a given location would thus equal the sum of the opportunity cost and the availability bid in dollars per MW of the most expensive unit accepted to provide that type of ancillary service in that hour to that location. As noted above, a generator providing any ancillary service is also technically capable of providing a slower response ancillary service. For example, a generator providing operating reserve—spinning could also provide operating reserve—supplemental. Thus the opportunity cost of providing operating reserves—spinning would be at least as high as the price of operating reserve—supplemental. As a result, the marginal cost (and thus, the price) of operating reserve—spinning would not be less than the price of operating reserve—supplemental in the same hour.

295. Although suppliers bid to provide these ancillary services in the day-ahead market, customers pay for them based on real-time load. Transmission customers would be assessed a *pro rata* share of the total ancillary service requirements for each of these three ancillary services in each hour, based on their real-time, load-ratio share. Ancillary service requirements generally depend more on real-time transactions than on day-ahead schedules. Assessing ancillary service requirements based on day-ahead schedules would provide an incentive for customers to understate their day-ahead schedules.

296. In Order No. 888, exports are not charged for these ancillary services. We ask for comments on whether they should be charged here.

297. Customers that want to self-provide or procure their own ancillary services would be required to notify the Independent Transmission Provider in the day-ahead scheduling process and identify the resources that would be used to provide these services. Customers would be given credit for the amount of ancillary services that they self-provide or procure from third parties. Customers that self-provide or procure from third parties more capacity than their requirements would be paid the applicable hourly ancillary service price for the excess if needed by the market.[152]

2. Scheduling After the Close of the Day-Ahead Market

a. Replacement Reserves

298. The Independent Transmission Provider will use the day-ahead market to develop prices and a schedule for suppliers. The prices and schedules will be based on the bids submitted by buyers and sellers. However, the day-ahead schedule may be less than the forecasted load in real time and, if so, the Independent Transmission Provider would commit additional units to ensure that load can be met reliably in real time.

299. After the Independent Transmission Provider has established a day-ahead schedule and associated prices for energy, transmission service and ancillary services, it would make its own forecast of load within its market area for each hour of the following day. To the extent that its forecasted load exceeds the amount of energy scheduled to be delivered to load in the day-ahead schedule, the Independent Transmission Provider may need to procure additional reserves (called "replacement" reserves) from generators to make up the difference, but only to

[150] Because of the way that prices would be established in each market, the market into which each bidder of generation capacity or demand-side resource is scheduled would also be the market that is the most profitable for the bidder. That is because, as discussed in the following section, the prices in each market would reflect marginal opportunity costs of the bidders in that market. Thus, the price in each market would be high enough to allow each accepted bidder in that market to receive at least as much profit as it could have received in any other market operated by the Independent Transmission Provider that it is technically capable of participating in.

[151] Because prices are determined hourly, an opportunity cost expressed in dollars per MWh converts to an equivalent dollar-per-MW basis.

[152] Since the customer's day-ahead schedule was based on its projected share of the ancillary service requirement, it may have procided more than its actual share in real time. Thus, the customer would be comlpensated for the additional amounts it provided.

the extent necessary to ensure that sufficient generation will be available to meet load.

300. To procure replacement reserves, the Independent Transmission Provider would accept bids from generators submitted for the day-ahead market. The Independent Transmission Provider would select generators to provide replacement reserves so as to minimize the costs of availability, start-up costs and no-load costs regardless of energy costs. This approach to procuring replacement reserves would provide an incentive for load to accurately bid its load in the day-ahead market since energy prices may be higher in the real-time market.

301. As discussed further in the next section, generators selected to provide replacement reserves would be included in the real-time energy bid stack along with other generators that submit bids into the real-time market to provide energy. Generators selected to provide replacement reserves would be paid the applicable real-time energy price for energy that they produce. If a generator's revenues received from selling real-time energy are less than its bids for availability, start-up, no-load and energy, the Independent Transmission Provider would pay the generator an additional payment (*i.e.*, an ''uplift'' payment) for the shortfall. The revenue shortfall would be recovered *pro rata* from all loads that buy energy in real time that have not been scheduled in the day-ahead market. Thus, the costs would be allocated to the customers that benefitted from the replacement reserves—customers that took power in real time. This provides an incentive for load to accurately predict its requirements in the day-ahead market.

302. We propose to add a new Section G.2 to the *pro forma* tariff that would implement the foregoing procedures for scheduling and paying for reserves after the close of the day-ahead market.

b. Changes to Transmission Schedules

303. A market participant that has not scheduled transmission service in the day-ahead market but desires transmission service in real time must inform the Independent Transmission Provider within specific time deadlines before real time. Market participants may change their day-ahead transmission service schedule by informing the Independent Transmission Provider consistent with the time deadlines.

304. Participants that have informed the Independent Transmission Provider of their desired changes within the Independent Transmission Provider's lead times, and adhere to the requested changes in real time, would settle the changes in transmission service at the applicable real-time transmission usage prices, described more fully below. Participants with new or increased transmission service would be charged the applicable real-time transmission usage price between the applicable receipt and delivery points for the new or increased transmission service in the applicable hour. Conversely, participants that reduce transmission service in real time (compared to the day-ahead schedule) would be paid the applicable hourly real-time transmission usage price for the applicable receipt and delivery points, to compensate them for the additional transmission capacity they have made available in real time.

3. Design of the Real-Time Markets

305. Under Standard Market Design, the Independent Transmission Provider would be required to operate bid-based, security-constrained real-time markets for transmission service, energy, and certain ancillary services (*i.e.*, regulation, operating reserve—spinning and operating reserve—supplemental).

a. Real-time Energy Markets

(1) General Features.

306. Under the Standard Market Design, the Independent Transmission Provider would accept bids to buy and sell energy in each hour in the real-time energy market. The bids would be in the standardized form specified by the Independent Transmission Provider. Real-time energy markets would be used to provide the energy imbalance service of Order No. 888 *pro forma* tariff. However, loads could voluntarily enter into bilateral contracts with suppliers in advance to lock in a fixed price for energy.

(2) Bidding and Scheduling Rules.

307. In general, bids would indicate an offer to depart in real time from the bidder's day-ahead schedule to purchase or sell energy (including a day-ahead schedule to purchase or sell 0 MWhs of energy). Real-time bids would be accepted from any market participant, including generators, load-serving entities, eligible retail buyers, marketers and other agents. Bids would indicate the increase or decrease (in MWhs) from the day-ahead schedule in the amount of energy to be sold or purchased in real time, and the location and the hour of the changed purchase or sale. Each participant bidding into the real-time energy market would be allowed to include multi-part price bids similar to those allowed in the day-ahead energy market (this is a departure from the Working Paper).

308. The transactions in real time vary from those reflected in the day-ahead schedule due to a variety of factors, including changes in weather conditions and unexpected equipment outages. The Independent Transmission Provider may be informed in advance of some of the scheduling departures under the procedures described above; other departures may occur without warning.

309. As occurs today, an Independent Transmission Provider will have to adjust energy production and/or load at various locations in order to balance generation with load and manage congestion. Under Standard Market Design, the Independent Transmission Provider would make these adjustments by calling upon participants that have submitted bids into the real-time energy market, as well as participants that have been selected to provide spinning, supplemental, and replacement reserves. The Independent Transmission Provider would issue dispatch instructions to bidders so as to balance generation and load, and efficiently manage congestion of demand and supply.

(3) Price Determination and Settlement.

310. The Independent Transmission Provider would determine energy prices in the real-time energy market for each node for each 5-minute period or other subhourly period where a 5-minute determination is not technically achievable. Each price would reflect the marginal cost (as reflected in the real-time supply and demand bids) of producing energy and delivering it to the node in that period. The Independent Transmission Provider would post prices and other market information and settle the markets promptly to give market participants reliable information regarding their market transactions.

311. To promote efficient participant decisions regarding real-time transactions, we propose that all departures in real time from the day-ahead schedule be settled through the real-time market at the applicable price (as is done today in many markets). Nodal pricing would be used for both buyers and sellers in the real-time market.

312. There are several aspects of the design of the real-time energy market where we seek additional comments.

Ex Post Versus Ex Ante Prices

313. This Section discusses how to determine real-time energy prices. The options are to set the prices using near

real-time estimates (*ex ante*), or base the price on the price of the actual marginal resource clearing the market in real time (*ex post*). Immediately in advance of each upcoming 5-minute period, the Independent Transmission Provider would announce the real-time energy prices that it estimates will clear the market and match generation with load during that upcoming period (based on the real-time bids submitted by market participants). The Independent Transmission Provider could settle all departures in real-time from the day-ahead schedule using these prices announced in advance. Such an *ex ante* pricing policy would provide price certainty and thereby encourage buyers and sellers that have not submitted bids to adjust their transactions in response to the announced price.

314. Alternatively, an *ex post* pricing policy could be used as an incentive for suppliers to follow dispatch instructions. Some bidders may not respond to the announced prices in the way suggested in their bids. For example, a supplier stating in its bid that it would increase its output by 50 MWh for each price increase of $5/MWh may in fact increase its output by less than 50 MWh in response to such a price increase. By settling at the ex ante price, the generator would be paid the higher price despite the fact that it did not increase its output as it had promised in its bid. An *ex post* pricing rule might help to encourage bidders to respond in real time in a way consistent with their bids. Specifically, the price used to settle real-time deviations from day-ahead schedules could be the price-bid associated with the energy observed *ex post* to be produced by the marginal supplier in the 5-minute period (but not higher than the advisory price announced *ex ante*). Such an *ex post* price rule would encourage suppliers to supply the full amount of energy promised in their bids.

315. We propose to adopt the *ex post* rule because it creates incentives for bidders to act consistent with their bids. We seek comment on the choice between *ex post* and *ex ante* pricing.

Other Charges for Uninstructed Deviations From Schedules

316. We seek comment on whether market participants should face additional charges for ''uninstructed'' deviations in real time from their schedules, *i.e.*, for producing or taking a different amount of energy in real time than was scheduled without permission or direction from the Independent Transmission Provider. Uninstructed deviations from schedules may increase the amount of regulation service or other ancillary services that the Independent Transmission Provider must procure, in order to reliably balance load and generation. If so, it would be appropriate to recover the costs of these services through a charge. We seek comment on whether the increased costs of regulation service or ancillary services should be allocated to the entities (buyers and sellers) that had uninstructed deviations from their schedules since the costs were incurred to serve these entities. Uninstructed deviations may also require the use of scarce ramping capability within the Independent Transmission Provider's market area. If ramping capability were used, it may be appropriate to charge for that use. We seek comment on whether and how to establish market prices for ramping capability. Finally, in extreme cases large uninstructed deviations can threaten reliability of service. To discourage this type of conduct a penalty provision may be appropriate.[153] We seek comment on whether the SMD Tariff should include penalty provisions for uninstructed deviations that threaten system reliability and how such penalty provisions should be structured.

What Bids Should Be Eligible To Set the Energy Price

317. Strictly speaking, the marginal cost of meeting a small increment of load would be based on the bids of suppliers whose output can be increased, or buyers whose load can be decreased, from their scheduled level in the hour by as little as 1 MW. Thus, for example, the marginal cost of supplying load in an hour would not be based on the bid of any generator that is operating in the hour solely because of a minimum run constraint, because changes in load would not change the output of the generator.[154]

318. However, we are concerned that by excluding generators whose output is adjustable in increments greater than 1 MW, on an hourly basis, from setting the energy price may not promote efficient results.[155] These potential inefficient results are more likely to occur in the real-time market than in the day-ahead market.[156] Therefore, we propose to allow generators whose output is adjustable on an hourly basis, but only in increments greater that 1 MW, to be eligible to set the energy price in the Real-Time Market if two conditions are met. First, the generator's output must be needed to meet load in the hour. That is, in the absence of the generator's output, either load could not be fully met or a more expensive generator would be needed to fully meet load. Second, the reason that the generator is operating must not be a minimum run time constraint. We also propose that any cheaper generators that are directed to reduce their output would be paid their opportunity costs (*i.e.*, the difference between the applicable energy price and their energy bids) for the amount of the output reduction. With this payment, the generator is compensated for the legitimate opportunity cost of following the Independent Transmission Provider's instructions.[157]

319. We seek comment on whether such lumpy generators should also be eligible to set the energy price in the day-ahead market. Although allowing these lumpy generators to set the energy price may have more direct benefit in the real-time market, we are concerned about potential negative ramifications from establishing different pricing rules for the day-ahead and real-time markets.

b. Real-Time Ancillary Services Markets

320. As discussed earlier, Order No. 888 requires transmission providers to offer to provide to transmission customers energy imbalance service, regulation and frequency response, operating reserve—spinning and operating reserve—supplemental. Under Standard Market Design, energy

[153] This penalty would be in addition to any penalties incurred for violating curtailment orders.

[154] Also, a generator that is operating at its low operating limit would not be able to set the market-clearing price.

[155] When such ''lumpy'' generators are needed to meet incremental load, it may be necessary to reduce the output of cheaper but more flexible generators (*i.e.,* generators whose output can be adjusted in 1 MW increments.) For example, to meet a 30 MW increase in load, the cheapest available generator (with a bid of $80/MWh) may be a combustion turbine with a capacity of 50 MW that can produce only at its maximum capacity. By operating the combustion turbine at 50 MW, the output of a cheaper flexible generator (with a bid of $60/MWh) would need to be reduced by 20 MW in order to match the 30 MW increase in load with the net increase in generated output. Once the flexible $60 generator is backed down, incremental load would be met with output from the flexible generator, so the marginal cost of meeting load would be $60. However, it would not be efficient to meet the additional load unless the load valued electricity at more than $80, the cost of the combustion turbine.

[156] In the real-time market, some market participants that have not submitted bids may nevertheless adjust their production or consumption. Thus, the rules for setting energy prices in the real-time market should consider these possible effects on market participants that have not submitted bids. By contrast, day-ahead schedules are based only on bids and self-schedules submitted to the Independent Transmission Provider, so day-ahead prices cannot result in any unexpected changes in the day-ahead schedule.

[157] These payments would be recovered through an uplift charge to loads that purchase from the Independent Transmission Provider's markets.

imbalance service would be provided through the transmission provider's real-time energy market. The Independent Transmission Provider would procure its expected requirements for the remaining three ancillary services through day-ahead ancillary service markets discussed above.

321. We propose that the Independent Transmission Provider operate a real-time ancillary services market to accommodate adjustments in the supply of ancillary services from the day-ahead schedule. In real time, there may be entities that can provide ancillary services more efficiently than those that were scheduled in the day-ahead market. The real-time market would permit such efficient substitutions. Higher-cost suppliers scheduled in the day-ahead market would buy back their offer to provide ancillary services at the applicable real-time price, and other, lower-cost entities would be paid the real-time price to take over the supply of ancillary services. In addition, the Independent Transmission Provider may need an amount of ancillary services that differs from the amounts procured in the day-ahead market, for several reasons. For example, the requirements expected in the day-ahead market may differ from actual, real-time requirements, or participants scheduled to provide ancillary services may experience outages in real time. Under Standard Market Design, the Independent Transmission Provider would procure any additional ancillary services needed in real time through the real-time ancillary service markets that it operates.

322. In the real-time market, the Independent Transmission Provider would accept bids for each ancillary service. As in the day-ahead market, a participant could offer the same capacity in more than one ancillary service market. The real-time bids would contain the same types of information as those submitted into the day-ahead ancillary service markets, with one exception—we propose to exclude availability bids for spinning reserves and supplemental reserves in real time. The types of costs reflected in the availability bid to ensure that the supplier will be available to provide these reserves are incurred in the day-ahead time frame, not in real time.[158] There do not appear to be any incremental costs associated with providing these ancillary services in real time, other than the opportunity costs of forgoing sales in another market operated by the Independent Transmission Provider, and these opportunity costs would be reflected in the way that ancillary service prices are determined.[159]

323. The Independent Transmission Provider would consider all bids to sell ancillary services in real time and select those bids that minimize the overall cost of procuring additional ancillary services required in real time.

324. Based on the bids accepted in the real-time market, the Independent Transmission Provider would establish real-time ancillary service prices for each hour that reflect the marginal cost of each service. All participants supplying a given type of ancillary service in a given hour in real time (and to a given location, if there are locational ancillary service requirements) would be paid the applicable market clearing price.

325. Transmission customers that have not self-supplied or procured through third parties their full assigned ancillary service requirement would be assessed a *pro rata* share of the costs incurred by the Independent Transmission Provider for procuring ancillary services in real time.

4. Market Rules for Shortages or Emergencies

326. We believe the market rules discussed above in combination with the market mitigation measures and the resource adequacy requirement will result in an efficient system for matching supply and demand under most operating conditions. However, we recognize that when emergency situations do occur, changes may be needed to the market rules to comply with reliability requirements. In the event of a capacity shortage or emergency, local reliability rules and procedures (which typically combine NERC, regional reliability council and system operator guidelines) prescribe a series of actions that the system operator takes to maintain reliability. For example, procurement of reserves is reduced, typically in order of reserve quality (that is, supplemental reserve quantities are reduced before spinning reserve quantities). The system may be re-dispatched to adjust the location and responsiveness of remaining reserves. System operators have also traditionally called on emergency supplies from neighboring systems (in the past, these emergency purchases have taken place at pre-defined prices; increasingly, they are being made at market prices). Finally, steps are taken for voluntary and involuntary load-shedding. States typically approve in advance the retail curtailment plans of utilities.

327. In the markets proposed in the SMD Tariff, we envision that with more extensive demand-side participation, the potential for these types of capacity shortage or emergency situations will substantially diminish. However, system emergencies may occur. The existing *pro forma* tariff gives transmission providers the authority to curtail transmission service and take any other preventive action necessary to preserve system reliability. The SMD Tariff would continue to grant the Independent Transmission Provider this same authority. However, the actions taken to ensure system reliability can affect prices in the energy and ancillary service markets. Market participants should be aware of how these actions will affect pricing in the markets operated by the Independent Transmission Provider. To that end, the SMD Tariff requires Independent Transmission Providers to file proposals with the Commission regarding the implications for market pricing of each reliability procedure. These proposals would need to be consistent with the resource adequacy mechanisms discussed below, but could vary to reflect regional differences in reliability requirements. We seek comments on what, if any, more specific requirements should be included in the Final Rule.

G. Other Changes To Remove Undue Discrimination and Improve the Efficiency of the Markets Under Standard Market Design

328. The existing *pro forma* tariff was constructed primarily to apply to vertically integrated public utilities. It was the first step toward competitive electric power markets since it allowed alternate suppliers to access loads through an open access transmission tariff. It sought to replicate the terms and conditions under which the host public utility served its own loads. It also was the first step in separating the generation and transmission arms of a public utility.

329. But more changes are needed to further the development of regional competitive wholesale electric markets and assure comparable and non-discriminatory treatment of all market participants. Accordingly, the following revisions must be made to the *pro forma*

[158] For example, the supplier may need to commit in advance to pay workers to staff its facility. However, the supplier would be able to offer to supply spinning reserves and supplemental reserves in real time if its workers were already staffing its facility, so in real time the supplier would not incur increment costs to provide ancillary services.

[159] Providing regulation service, however, would typically impose incremental out-of-pocket costs on the supplier, due to the additional wear and tear on equipment associated with frequent adjustments in output that regulation suppliers must make.

tariff to change the market rules in ways that will improve the efficiency of wholesale electric markets.

1. Capacity Benefit Margin

330. Capacity Benefit Margin is the set-aside of transmission capability by a transmission provider to ensure the ability to import external resources to meet generation reliability requirements or in case of a generation capacity deficiency. During the Commission's outreach process, many commenters asserted that Capacity Benefit Margin ties up valuable transfer capability without a specific reservation and payment by the customers who receive the benefit of the set-aside. The subsidy occurs because, while part of the transfer capability is withheld from the market as Capacity Benefit Margin, the wholesale transmission customers using the system pay the entire transmission cost (including that of the Capacity Benefit Margin) through their transmission charges, thus subsidizing the Capacity Benefit Margin beneficiaries. The use of a Capacity Benefit Margin has also been regularly challenged on the grounds that the host transmission provider is withholding transfer capability under the guise of Capacity Benefit Margin in order to thwart competition.

331. We propose to standardize the treatment of Capacity Benefit Margin to ensure that (1) only customers benefitting from it pay for it, and (2) transfer capability needed to access resources on a neighboring system is treated consistent with all other portions of the transmission grid. Thus, an Independent Transmission Provider itself would not be permitted to set aside transfer capability for generation reliability reasons. Rather, a load-serving entity wanting access to resources on a neighboring transmission system to meet its resource adequacy requirement should instead acquire Congestion Revenue Rights from the interface to its load to ensure that access. This will free up transfer capability now unavailable to wholesale transmission customers and prevent cross-subsidization of transmission customers that serve load within the Independent Transmission Provider's service area by point-to-point transmission system users.[160]

332. This prohibition of the generic set-aside of transfer capability by the Independent Transmission Provider for generation reliability reasons does not apply to an Independent Transmission Provider's responsibility to set aside transfer capability to ensure transmission reliability (*e.g.*, to ensure that a line can take up the power flows it must absorb if a parallel line should go out of service or other uncertainties in system conditions arise). Such a set-aside is called Transmission Reliability Margin and must be consistent with good utility practice and should not be implemented in a way that favors particular transmission customers (*e.g.*, by release of the set-aside capability for use by native load).

2. Regional and Independent Calculation of Available Transfer Capability, Performance of Facilities Studies and OASIS

333. The Commission has found specific instances of abuse by transmission providers regarding the Available Transfer Capability calculation process and delays in the completion of transmission facilities studies.[161] There are obvious incentives for a vertically integrated transmission provider to favor its own generation by delaying facilities studies or manipulating the Available Transfer Capability calculations or postings on its OASIS. Under Standard Market Design, calculations of transmission capability and the performance of facilities studies for transmission expansions must be performed by an independent entity to reduce the opportunity for preferential treatment by the transmission provider.

334. More broadly, the SMD Tariff must recognize the regional nature of today's energy markets. Transmission capabilities must be calculated not for a single utility's service territory, but regionally to encompass existing trading patterns and power flows, particularly parallel path flows on neighboring systems. All transmission providers that are not part of a Commission-approved RTO must contract with an independent entity to perform transmission capability calculations on a regional basis. Likewise, we propose to require a common OASIS for the region.

3. Regional Planning Process

335. Competitive and reliable regional power markets require adequate transmission infrastructure to allow geographically broad supply choices and minimize the complications created by loop flow. The recent DOE National Grid Study documented the problems resulting from recent under-investment in transmission infrastructure and identified a number of causes. Among the causes were the lack of regional planning and coordination of transmission needs and siting issues.

336. Transmission planning and expansion have generally been performed for a single control area rather than on a regional basis. This yields sub-optimal solutions, as individual transmission providers consider power flows across a limited area and do not adequately consider entire markets. Parallel path flows that occur on neighboring systems may make the construction of specific facilities less cost-effective than a regional solution. This effect can be properly considered by performing transmission planning and expansion on a regional basis. Moreover, facilities that, if constructed in one system would be the optimal solution for a neighboring system, might never be considered under a single control area-based planning model.

337. Implementation of Standard Market Design will only increase the importance of examining these issues on a regional basis. More open and transparent markets will enable customers to purchase from distant suppliers, increasing use of the grid. Locational marginal prices that result from the spot markets operated by an Independent Transmission Provider would signal to all market participants the value of additional supply and demand response at particular locations. Based on these prices over time, market participants will be able to decide whether additional investment—in transmission or generation facilities or demand response—is warranted. The ability of individual market participants to see the economics of possible solutions and make market-driven decisions concerning the addition of infrastructure is the fundamental mechanism that induces efficient investment under Standard Market Design. The policy relies primarily on a ''ground-up'' planning process that encourages construction by private companies yet also recognizes the need for a regional evaluation process for loop flow effects and cost-effectiveness. It is neutral with respect to the type of investment market participants may make in response to these price signals. However, due to loop flow, all system modifications would need to be coordinated through a regional process and would have to meet any criteria needed to maintain reliability and stability, and assure that existing customer rights are not impaired.

338. Given the need for transmission investment in much of the country and the time it will take to implement Standard Market Design and for

[160] To the extent that an Independent Transmission Provider's load ratio share access charge calculation does not pick up this reservation, the amount of interface capability can be imputed and added to the customer's peak day amount.

[161] *See* Section III and Appendix C.

investors to observe and respond to price signals, we propose that a regional planning process be instituted within six months of the effective date of the Final Rule. This process should be designed to identify beneficial transmission needed for both reliability and economic reasons to support regional markets and reduce the effects of generation concentration. The regional planning process should allow the market to respond to those identified needs.

339. A critical piece of the transmission planning process is state-level siting decisions. We note a recent National Governors' Association report that recommends Multi-State Entities to facilitate regional transmission planning decisions.[162] Multi-State Entities, along with an open regional planning process, would preserve the states' role in siting decisions, while promoting regional solutions. A Multi-State Entity could be an important component of the regional planning process.

340. Certain areas of the country and organizations already have proposals or processes to consider regional planning or development of regional markets. Building off of these existing efforts will help facilitate the development of a regional planning process in the near term. We emphasize that a planning area need not coincide with the geographic area of a Commission-approved RTO or Independent Transmission Provider required by this rule. Also, because of the interrelationships between Canadian and U.S. energy markets, we encourage participation by Canadian entities and provincial authorities in the regional planning process.

341. Current processes such as the Committee on Regional Electric Power Cooperation in the West provide for state and provincial advice in the planning across the entire Western grid. Therefore, we propose to use the area covered by Western Electricity Coordinating Council (WECC) that encompasses the geographic area covered by the Western Grid for regional planning purposes.

342. In the Eastern Interconnection there have been several efforts at developing regional wholesale electricity markets that we propose to build on for the regional planning process. PJM and MISO developed a Memorandum of Cooperation dated May 9, 2002 that commits to develop a joint and common wholesale electric market for PJM, MISO, and SPP. Consequently, we propose that the area covered by these organizations would also be a regional planning area.

343. Similarly, New York ISO and ISO-New England are currently pursuing discussions on the merger of these two organizations into a Northeast RTO. Both are also members of the Northeast Power Coordinating Council which has recently conducted studies of transmission needs in the region.[163] We propose to build on these efforts and use the area covered by these organizations as a planning area.

344. Finally, we recognize that there has been ongoing discussion development of regional markets in the Southeast. SETrans Regional Transmission Organization proposes to encompass a broad area in the Southeast. The Tennessee Valley Authority (TVA) has signed a Memorandum of Understanding with Southern Companies and Entergy, two sponsors of SETrans, to work together to develop coordination agreements. Additionally, the SETrans and GridSouth Transco, LLC parties signed a Memorandum of Understanding in January 2002 calling for similar regional coordination. Thus we propose to build on these efforts and propose a Southeast planning area composed of the Southeastern Electric Reliability Council and the Florida Reliability Coordinating Council.

345. We propose that all public utilities that own, control, or operate transmission facilities must participate in a regional planning process for the planning areas discussed above. We propose that this process start within six months after the effective date of the Final Rule and that the first regional transmission plan be completed within twelve months after the effective date of the Final Rule. Reliance on these existing regional efforts should facilitate the start-up of the regional planning process before Standard Market Design is implemented and all areas have Independent Transmission Providers operating transmission facilities.

346. After Standard Market Design is fully implemented, we believe the regional planning process will change as Independent Transmission Providers play a greater role in that process. There will still remain a significant need for a regional planning process to supplement private "ground up" investment decisions. The regional planning process is intended to supplement these private investment decisions, not supplant them. The regional planning process must provide a review of all proposed projects to assess whether the project would create loop flow issues that must be resolved on a regional basis. In addition, because of the externalities involved, there may be no private investment sponsor for some projects that would benefit the region. Private investment decisions in response to prices may not result in adequate expansions for two reasons. First, private parties may not be eligible to ask the state to exercise its eminent domain rights. Second, some needed and beneficial expansions may not create enough identifiable financial benefits to compensate private investors adequately, so those projects will not be built under a system that relies solely on private investment to expand the grid. A regional planning process can identify both the projects that would benefit the planning area and potential alternatives in a fair and unbiased manner. Additionally, a regional planning process, would evaluate the benefits of alternative proposals and provide an independent assessment of which projects are the most cost effective and/or have the least environmental impact.

347. To complement private investment initiatives, we propose that Independent Transmission Providers establish a mechanism for regional transmission planning and expansion guided by the following principles. First, the planning process should identify all expansion needs on the system, including both reliability and economic needs (*e.g.*, to reduce congestion). The planning process should leave open the question of how and by whom those needs should be met, without favoring one solution (whether it is transmission, generation or demand response) over another. The planning process should be open to all industry segments. Additionally, all entities could propose projects. As long as the project did not make existing Congestion Revenue Rights infeasible due to loop flow problems, the entity would be free to complete the project as long as it is willing to assume any market or regulatory risk. However, to the extent the entity sought to roll-in the costs of the facilities, the rate treatment should be reviewed through the planning process.

348. Second, an Independent Transmission Provider should have the responsibility to issue requests for proposals when the planning process determines that additional resources are needed to serve the regional market. Parties may respond with proposals to expand the grid, add generation (including distributed generation), or

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[162] *See* Interstate Strategies for Transmission Planning and Expansion, National Governors' Association, posted on July 18, 2002, *available in* <*http://www.nga.org/center/divisions/1,1188,C__ISSUE__BRIEF^D__4110,0.html*>.

[163] Northeast Power Coordinating Council *Collaborative Planning Initiative Phase I* issued March 13, 2002.

implement demand response.[164] The Independent Transmission Provider would approve transmission expansions that would be paid for by all customers only when planned private investments are judged to be inadequate to meet the reliability and market needs of the region. If the bidding process fails to produce a satisfactory outcome, such that the Independent Transmission Provider determines that additional facilities are needed, the affected transmission owner(s) would be required to expand or upgrade the transmission system.[165]

349. Finally, the Independent Transmission Provider would act as a clearinghouse for proposed projects. It could identify separate projects that could be constructed at a lower cost if the projects were combined. Also, if there are alternative projects that have been proposed, the Independent Transmission Provider could evaluate the relative advantages of the alternative projects.

350. This approach to regional planning and expansion is fully consistent with Standard Market Design's goal of inducing efficient investment by relying primarily on price signals and independently administered Congestion Revenue Rights. At the same time, it recognizes that private investment decisions may not be fully adequate in all cases because of eminent domain and the possibility that private benefits of investment could be significantly less than social benefits. The planning process would have a regional scope, permit direct competition among all types of investment, include all market participants equally, and minimize the need to rely on eminent domain and the support of captive customers. Because existing transmission owners are the transmission builder of last resort, it also respects the reality that not all states allow non-traditional utilities to build in their state or to obtain eminent domain, thus creating a legal barrier to entry.

4. Modular Software Design

351. Software and data issues have become an important part of the market design and changes to market design. On many occasions over the past several years, market designs and improvements have been delayed or even abandoned due to software constraints or software development costs. Software and data systems inherited from the old structure are often idiosyncratic, making changes and seams issues more difficult than they should be. Market participants often find software to be impenetrable ''black boxes.'' Software development and modifications have become expensive and software ''wheels'' are being reinvented. Consequently, the software used to implement the Standard Market Design's real-time and day-ahead markets will be a critical element in the feasibility and success of Standard Market Design.

352. The Standard Market Design software should have the following characteristics: transparency (the ability to understand what the software does), testability (the ability to understand and compare performance) and modularity (the ability to change software modules without changing other software). Transparency, modularity and testability help break down entry barriers and allow for competition in software development. Modularity requires standard interfaces (well-defined data inputs and outputs and ease of access). Since we expect Standard Market Design to evolve over time and wholesale markets to grow, the underlying software must be able to accommodate change. Scalability, security and robustness are desirable design features.

353. All market and operations software approximates the actual operation of the system. However, computational and feasibility issues are not well understood. Issues include performance, AC vs. DC models and consistency if both are used. Unit commitment models use different heuristics that were not important in the old vertical structure, but can be very important for new demand and supply entrants in a decentralized market. To instill confidence in the software, testing, validation and evaluation should be a part of an open process.

354. We propose to require that the software meet the characteristics set forth above and that the input and output data systems and other Electronic Data Interchange be standardized in a common data model including a data dictionary (glossary and/or data definitions) and common network description. We seek comment on the following questions.

355. The Commission held a conference on July 18, 2002, to discuss the operational data and software needed to implement Standard Market Design and large regional wholesale markets, following an earlier conference on software issues. Among the topics discussed were market operational software capabilities, software standardization, ISO experiences with implementing software, cyber-security and the need to achieve some standardization within the electric market and grid operations software modules across vendors.

356. The conference established that for most applications, software does not appear to be a binding constraint on the size of RTOs or the implementation of Standard Market Design. Participants noted that the computational algorithms inside the models are continually improving, as is the speed of the processors used to solve the models, so it is reasonable to expect that software and associated hardware needs should keep pace with market span.

357. The Commission's goal is to assure that the best software is available for use in the nation's wholesale markets. This can best be attained by promoting competition among vendors, in a way that assures that no vendor comes to ''own'' a market niche or impose barriers to entry by new software companies with innovative analytical approaches.

358. Many vendors have particular areas of expertise and their software is often integrated with other software in complete software systems. We propose to encourage the development of ''plug-and-play'' software designs so that the best modules can be integrated into complete market operational systems for Independent Transmission Providers. To accomplish this we need to standardize data transfer between modules. Participants at the conference proposed two ways of accomplishing this—open systems and standardization. The open systems approach would leave it to each vendor to develop and publish the interface to the next module in the system. The standardization approach would define a set of minimum specific standard functions for each software module and specify the interfaces to be used between modules. We believe that the standardization approach is best suited to the close time frame needed for Standard Market Design implementation, and invite comment on the best process to develop these standards—should we use the evolving NAESB process or forums set up by the Electric Power Research Institute for this purpose, or use another approach?

359. The discussion of a suite of benchmark problems to test software illustrated the importance of benchmarking to facilitate testing and comparison of candidate software with respect to solution outcomes and processing time. We therefore encourage

[164] We recognize that the states have the ultimate authority over siting.

[165] *See* existing *pro forma* tariff §§ 13.5 and 15.4 (transmission provider required to expand its transmission system if transmission customer agrees to compensate the transmission provider). This requirement extends to the transmission owners.

the industry to develop such a suite of benchmark or test problems.

360. As a follow-up to the July 18, 2002 Standard Market Design software conference, the Commission will hold another conference on these topics on October 3, 2002. This conference will focus particularly and in detail on what process or body should be used to set standards for data standardization for inputs and outputs to software modules; whether the standards already developed by the Ontario Independent Market Operator for this purpose might be applicable for United States markets;[166] and how to proceed with the development of test problems for evaluating and comparing software modules.

5. Transmission Facilities That Must Be Under the Control of an Independent Transmission Provider

361. In a variety of public forums, including RTO conferences and comments to RTO proceedings, much uncertainty has been expressed concerning two questions: which facilities belong under the control of the RTO; and which customer-owned transmission facilities that are turned over to RTO control are entitled to a credit? [167] In some instances, the dispute centers on whether the facilities are integrated. Other disputes involve the voltage level at which a facility is determined to be transmission. Under this proposed rule, the question becomes which transmission facilities must be under the control or an Independent Transmission Provider, be it an RTO or not.

a. Before Order No. 888

362. Before Order No. 888, much of the industry consisted of vertically integrated investor-owned utilities (IOUs) that, for the most part, provided a single service—bundled requirements power—to retail and wholesale customers alike. The classification of delivery facilities between transmission and distribution came up only in a ratemaking context. Because wholesale requirements customers purchased bulk power, they often did not require service over distribution facilities. Often, only a stepdown substation or a feeder line was involved. For those few stand-alone transmission services that an IOU might provide, the cost allocation issue was the same. The Commission approached this allocation issue by defining an integrated transmission grid as those facilities that operate in a single cohesive fashion to deliver bulk power and allocating wholesale (and stand-alone transmission customers) a proportional share of the embedded costs of those facilities on a rolled-in basis with postage stamp pricing.

363. Infrequently, the Commission would consider rate treatments premised on the distinction between transmission and subtransmission (high and low voltage transmission). If there were delivery facilities (transmission or distribution) that were not part of the integrated grid, but were used by a specific wholesale customer (*e.g.*, radial tap line or stepdown substation), the Commission would allow the direct assignment of those facility costs in wholesale rates.

364. These issues were discussed at length in Commission cases in the 1970s when IOUs attempted to bifurcate the pricing (effectively pancaking) and thereby increase their wholesale revenues. Customers, on the other hand, wanted to classify facilities as transmission and thereby decrease their delivered energy charges by only paying one charge for these facilities. While the issue was often framed as a transmission/distribution issue, it was mostly a battle over utilities trying to pancake rates (through charging a rolled-in rate plus a direct assignment charge) for transmission facilities or facilities that provided both transmission and distribution functions (dual-function facilities).

b. Order No. 888

365. Order No. 888 did not require a change in traditional rate treatments. However, since the Commission issued its open access rules, a number of utilities have proposed subclassifications of transmission, *e.g.*, transmission and subtransmission. Protestors (generally transmission-dependent utilities) have argued that this rate treatment favors transmission users that are connected to the transmission system at higher voltages (*i.e.*, the transmission owners' own generation) by reducing their rates for open access transmission service (because they pay only the high-voltage charge) and that reclassification is just another way to pancake rates and increase charges to low-voltage users. During the Commission's public outreach, commenters pointed to such splits as the pool transmission facilities (PTF)/non-pool transmission facilities in ISO New England as an example. This is not a consistent classification of pool transmission facilities and non-pool transmission facilities among transmission owners in New England. A generator located on a lower voltage portion of the ISO's grid must pay an additional non-PTF charge to access the New England market, but other, generators do not, putting the first generator at a competitive disadvantage.

366. The issue of transmission/distribution classification in Order No. 888 was in the context of unbundled retail transmission service and the Federal Power Act's legal jurisdiction distinction between ''transmission'' facilities (subject to Commission jurisdiction) and ''local distribution'' facilities (subject to state or local jurisdiction). To determine what facilities would be under Commission jurisdiction for purposes of the Order No. 888 open access requirements and what facilities would remain subject to state jurisdiction for purposes of retail stranded cost adders or other retail regulatory purposes, the Commission developed a seven factor test to determine what facilities are transmission facilities and what facilities are local distribution facilities.[168] With respect to the seven factor test, the Commission also stated that it would defer to the state commission's findings as to what facilities constitute local distribution facilities if the state's determination was consistent with our comparability principles. In addition, dual purpose facilities, *i.e.*, those used both for transmission or wholesale sales and for local distribution, would fall under the Commission's jurisdiction. To the extent use of particular facilities changed over time, the Commission would revisit these determinations. The Supreme Court upheld these determinations upon appellate review.[169]

c. Test for Transmission Facilities

367. Order No. 888's seven factor test was designed to determine the local distribution component of an unbundled retail sale. The test did not exist prior to Order No. 888 and in fact was created to do something the Commission had never done before—identify local (retail) distribution facilities. Thus, the test identifies all facilities that are not local distribution facilities. We propose that this is the appropriate starting point for determining which facilities belong under the control of an Independent Transmission Provider. To the extent that a transmission owner or Independent Transmission Provider

[166] *See http://www.oeb.gov.on.ca/english/electronic__business__standards.htm* last visited July 30, 2002.

[167] *See, e.g.,* City of Vernon, California, 93 FERC ¶ 61,103 (2000), 94 FERC ¶ 61,344 and 61,148 (2001); 95 FERC ¶ 61,274 (2001); and 96 FERC ¶ 61,312 (2001).

[168] Order 888 at 31,771.

[169] *New York* v. *FERC,* 122 S. Ct. 1012.

believes that certain facilities should not be under the Independent Transmission Provider's control, the Independent Transmission Provider may request an exception to this presumptive determination.

368. This proposed test focuses on the presumption that, if a facility is transmission, it belongs under the control of the Independent Transmission Provider. Thus, once a determination is made with the seven factor test, there would be no need for an additional review under the Commission's previous integrated facilities test. In *MidAmerican Energy Company,*[170] the Commission explained that the Commission's determination of which facilities are transmission is fluid and dependent on actual use of the facilities:

> Although we are accepting the state commissions' classification, we reiterate our finding in Order No. 888 that to the extent that any facilities, regardless of their original nominal classification, in fact, prove to be used by public utilities to provide transmission service in interstate commerce in order to deliver power and energy to wholesale purchasers, such facilities become subject to this Commission's jurisdiction and review.[171] In addition, the rates, terms and conditions of all wholesale and unbundled retail transmission service provided by public utilities in interstate commerce are subject to this Commission's jurisdiction and review.[172]
>
> Further, our deference in this proceeding does not affect the Commission's separate determination of what facilities must be under the operational control of RTOs, including ISOs and Transcos.[173] The Commission will make this latter determination, taking into account the seven factors formulated for purposes of determining jurisdiction as set forth in Order No. 888,[174] the ISO principles set forth in Order No. 888,[175] and the principles set forth in the RTO Final Rule.[176]

We note that the determination of which facilities are under the operational control of the Independent Transmission Provider does not dictate transmission pricing.[177]

369. We request comment whether, either in addition to or in lieu of the seven factor test, the Commission should use a bright line voltage test (*e.g.*, 69 kV) to determine which facilities are placed under the control of the Independent Transmission Provider. If so, we seek comment on the bright line, whether we should allow regional variation, and how transmission facilities that are not placed under the control of the Independent Transmission Provider's tariff are treated with respect to open access and rates.

H. Transition to Single Transmission Tariff

370. This section discusses the transition process that will be used to move from the existing *pro forma* tariff to the SMD Tariff. First, we discuss the provisions of the revised tariff that remain the same as those in the existing *pro forma* tariff, but may change based on the comments received in response to our questions. Second, we discuss the provisions we propose to change. When Standard Market Design is implemented, the revised tariff would apply to nearly all transmission services on the system. All customers would receive the same quality and quantity of service they currently receive. Customers currently taking transmission service under an open access transmission tariff would continue to do so, but now would be served under the new Network Access Service under a revised open access transmission tariff. Bundled retail customers would continue to receive service from their existing load-serving entity; however, the load-serving entity would be required to take service under the new Network Access Service *pro forma* tariff in order to serve those retail customers. Similarly, while wholesale customers with pre-Order No. 888 contracts would be given the opportunity to convert to the new transmission service under a revised open access transmission tariff, if they choose not to do so, the transmission owner that provides service under the pre-888 contract would be required to take service under the new Network Access Service *pro forma* tariff in order to meet its contractual obligations to serve those customers.

371. Standard Market Design is intended to cure undue discrimination, more efficiently use the transmission grid and give customers additional options. To help ensure that the transition process satisfies these objectives, the proposed rule would allow certain regional flexibility in the implementation process to the SMD Tariff. In particular, the regions would have flexibility in converting the rights of existing customers to Congestion Revenue Rights or auction revenues under the new tariff. Also, the regions would have flexibility in establishing the rate design for the new Independent Transmission Providers. It is anticipated that the state representatives, through the Regional State Advisory Committees discussed in Section IV.K., will play an active role in these regional decisions.

1. Treatment of Customers Under Existing Wholesale Contracts

372. When the Commission issued Order No. 888 it faced the issue of what to do with existing contracts. The Commission decided that it would not generically abrogate existing requirements and transmission contracts, but that under all post-Order No. 888 contracts were to conform to the Order No. 888 *pro forma* tariff.

373. Similarly, we propose not to abrogate existing pre-Order No. 888 contracts. On a nationwide basis, these contracts should represent a relatively small portion of the total load and should be able to be accommodated within the Standard Market Design.[178] The customers with these contracts will be able to convert these existing contracts, consistent with their contract terms, to the new Network Access Service upon implementation of Standard Market Design. However, as discussed below, if customers choose not to convert to the new service, the transmission owner would be required to take service under the new tariff in order to meet its contractual obligations to serve the pre-Order No. 888 contract customers.

374. If pre-Order No. 888 contracts remain in effect, the contracting transmission owner would be required to take service from the Independent Transmission Provider in order to serve its existing wholesale power or

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[170] 90 FERC ¶ 61,105 (2000).

[171] In Order No. 888, the Commission explained that ''a public utility's facilities used to deliver electric energy to a wholesale purchaser, whether labeled ''transmission,'' ''distribution,'' or ''local distribution,'' are subject to the Commission's exclusive jurisdiction under sections 205 and 206 of the FPA.'' Order No. 888 at 31,969; *accord* Nevada Power Company, 88 FERC ¶ 61,234 at 61,768 (1999).

[172] Transmission service in interstate commerce by public utilities, including the rates, terms and conditions for such service, remains within this Commission's exclusive jurisdiction. 16 U.S.C. 824, 824d, 824e (1994). *See* generally Order No. 888–A at 30,339–41.

[173] Which facilities will or will not be under an RTO's operational control also does not predetermine transmission pricing, cost allocation, or rate design determinations at either a state commission or at this Commission.

[174] Order No. 888 at 31,771.

[175] Order No. 888 at 31,730–32.

[176] Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. ¶ (1999) (RTO Final Rule).

[177] As noted in *MidAmerican,* present ISO agreements obligate transmission owners to provide access over facilities that are not under the control of the ISO if those facilities are needed to provide wholesale transmission service regardless of ownership or whether those facilities are labeled transmission, distribution (*i.e.*, distribution facilities other than local distribution), or local distribution. The same holds for Independent Transmission Providers.

[178] It appears that these contracts would be less than 10 percent of total load on a nationwide basis based on data from Form No. 1 filings by public utilities for calendar year 2000.

transmission contract. The Independent Transmission Provider will assess the transmission owner for all charges and payments for providing the transmission service. The transmission owner will receive the allocation of initial Congestion Revenue Rights (or auction revenues associated with Congestion Revenue Rights) to provide protection against congestion costs for these existing contracts. If the ultimate transmission customer prefers having a direct allocation of these rights, it can convert the contract, subject to any contractual limitations, so that the customer directly receives service through a service agreement under the SMD Tariff and would take service directly from the Independent Transmission Provider.[179] We expect that the Congestion Revenue Rights or auction revenues for Congestion Revenue Rights that the transmission owner will receive in association with these contracts will be sufficient to cover increased congestion costs that would result from having the transmission owner take service under the new tariff in order to serve its wholesale requirements customers. However, the transmission owner would have the right to make a filing pursuant to section 205 of the Federal Power Act to demonstrate that its revenue requirement should be adjusted to recover additional costs caused by implementation of this provision.

375. The Commission is concerned that pre-Order No. 888 contracts could permit the parties to extend a contract indefinitely through the use of roll-over or evergreen provisions in the contracts. The Commission seeks comment on whether it should limit the ability of the parties to extend these contracts past their initial term, or if that has passed the end of the next roll-over period and, if so, what limitations are appropriate.

2. Allocation of Congestion Revenue Rights

376. The initial allocation of Congestion Revenue Rights is important to ensure that the implementation of Standard Market Design preserves the service rights of existing customers, provides access to all available capacity and minimizes cost shifts. We offer a process for this transition. First, the Independent Transmission Provider would compile a catalogue of all the existing long-term firm obligations for its transmission system that would still be in effect when Standard Market Design is implemented.[180] This would include firm Point-to-Point Transmission Service under an open access transmission tariff,[181] firm transmission under pre-Order No. 888 contracts, designated resources for network transmission service pursuant to an open access transmission tariff, and bundled retail load (which is served under an implicit contract with the transmission owner). For firm Point-to-Point Transmission Service, the existing rights would be those specified in existing service agreements. For network transmission service and bundled retail transmission service, the existing rights would be limited to the designated resources in effect at the time, up to an amount equal to the customer's current peak load since this would replicate the service the customer is currently receiving. The Congestion Revenue Rights would go to the entity taking service under the Independent Transmission Provider's tariff. In general, these customers would not be granted an initial allocation based on additions for future load growth, but would have to secure those rights. However, there are instances where the vertically integrated transmission provider has identified load growth and limited the term (and rollover rights) of point-to-point transmission contracts. We seek comment as to whether and under what circumstances load growth should be accommodated in the direct allocation of Congestion Revenue Rights. The initial Congestion Revenue Rights would be receipt point-to-delivery point obligations.

377. Next, the catalogue of firm obligations would be subject to a simultaneous feasibility test.[182] On some systems, it may not be possible to award Congestion Revenue Rights that are simultaneously feasible to all of the existing firm transmission customers on the system, because the system may be leveraging load diversity—different customers using the grid at different times—to meet the peak needs of all users. If those needs cannot all be met simultaneously, then not all customers can have annual Congestion Revenue Rights equal to their peak usage,[183] then the initial allocation of Congestion Revenue Rights would be limited to the amount that is simultaneously feasible. The Congestion Revenue Rights could be allocated between customers on a *pro rata* basis or customers could be given the opportunity to change receipt points to achieve a simultaneously feasible result, or the Congestion Revenue Rights could be restricted to certain periods.[184]

378. Either of two methods could ensure that current customers receive the value of their current contracts (actual or implicit)—direct assignment and an auction with a revenue assignment.[185] First, Congestion Revenue Rights could be directly assigned to the customers that currently have the receipt points and delivery points identified in their existing contracts (actual or implicit). Under this approach, a customer that currently has a firm point-to-point transmission contract for 100 MW from point A to point B would receive 100 MW of Congestion Revenue Rights from point A to point B for the length of its contract. A network customer or a load-serving entity serving retail load that has identified a network resource for 100 MW of capacity would receive a Congestion Revenue Right for 100 MW from that receipt point to the customer's load.[186] The delivery points would be defined as the customer's interface points with the Transmission Provider. For network contracts and implicit contract, it is likely that customers would continue service for the foreseeable future (without a contract termination date). Thus, we seek comment on what type of term should be used for purposes of the Congestion Revenue Rights allocation for these contracts.

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[179] To the extent that there are contractual limitations, the customer could seek modification of the contract through a filing with the Commission.

[180] Network transmission contracts are not currently assignable because they do not consist of reservations from particular receipt points to delivery points in specific stated amounts. Therefore, some measure of historical usage on a point-to-point basis will have to be imputed to each network customer in order to assign Congestion Revenue Rights.

[181] Short-term firm contracts would expire before the implementation of Standard Market Design and would thus not be included in the catalogue.

[182] Simultaneously feasibility means that power can be simultaneously transmitted from the receipt points to the delivery points specified in the Congestion Revenue Rights in a contingency-constrained dispatch. If this power flow does not cause overloads on the system (either pre- or post-contingency), then the power flow is simultaneously feasible.

[183] Congestion Revenue Rights that give a holder different seasonal quantities could be an option in such a case.

[184] If the simultaneous feasibility tests indicate there are additional Congestion Revenue Rights that could be offered, these Congestion Revenue Rights will be offered through an auction open to all customers.

[185] For the sake of simplification, this discussion assumes that simultaneously feasible Congestion Revenue Rights could be issued to replicate current rights. If adjustments need to be made to ensure a simultaneously feasible result, the numbers may change, but the same basic methodology would be used for the conversion process.

[186] In states that have retail competition, provisions would also be needed to ensure that the Congestion Revenue Rights stay with the load. So if a new retail marketer starts serving load previously served by the local utility, the retail marketer would get a proportionate share of the Congestion Revenue Rights.

379. Alternatively, current firm customers could be given the auction revenues from the sale of Congestion Revenue Rights. Thus, the existing customers would receive the market value of those rights. Under this approach, all of the Congestion Revenue Rights available on the system would be sold through an auction. At a minimum, the Congestion Revenue Rights sold in the initial auction would have to include point-to-point obligations. If there is interest from market participants and it is technically feasible, the auction could also include point-to-point options and flowgate rights.

380. The terms of the Congestion Revenue Rights would vary. Initially, a set percentage would be auctioned on a monthly basis, another set percentage would be auctioned for six months and another for one year. This rulemaking proposes that the regions be given flexibility in setting the initial terms for the Congestion Revenue Rights sold in auctions. Since congestion patterns can change significantly after the implementation of LMP, there may be a benefit to delaying the auction of multi-year Congestion Revenue Rights until after a start-up period. On the other hand, customers may desire long-term Congestion Revenue Rights to correspond to the term of the long-term contracts used to satisfy the long-term resource adequacy requirement. We seek comment on whether we should require long-term Congestion Revenue Rights in such cases. The Congestion Revenue Rights that would be sold during the initial auction would be the set of Congestion Revenue Rights that maximizes the value of the awarded Congestion Revenue Rights based on buyers' bids that is simultaneously feasible. The revenues from the auction would be given to the customers that are paying for the embedded costs of the system through an access charge.

381. In the long-term, the auction methodology has a number of advantages over the allocation methodology in a competitive wholesale market. First, the auction methodology makes it easier for load-serving entities to change receipt points (and thus supply sources) and obtain protection against congestion costs because of the more frequent auctions for Congestion Revenue Rights. The same would also apply to sellers seeking to sell to different buyers. In contrast, if Congestion Revenue Rights are directly assigned, holders of the Congestion Revenue Rights on congested paths may be reluctant to offer these in the secondary market. This could limit the ability of new suppliers to enter the market. This could be problematic particularly with Congestion Revenue Rights held by vertically-integrated utilities. Second, experience to date has been that there is a more vibrant secondary market where Congestion Revenue Rights are auctioned rather than directly assigned.[187]

382. This proposed rule establishes a preference for the auction of Congestion Revenue Rights. After a transition period, all Independent Transmission Providers would be required to auction their Congestion Revenue Rights. However, for an initial transition period of four years, this rulemaking proposes to allow regional flexibility on this issue. During a transition period, the Independent Transmission Provider after consultation with the Regional State Advisory Committee and stakeholders in a region, could decide to directly assign Congestion Revenue Rights. At the end of the transition period, the Independent Transmission Provider would be required to submit a filing to move to an auction for Congestion Revenue Rights with the auction revenues allocated to those that pay the access charge, or justify why a longer transition period is necessary. The customer that previously had been allocated the Congestion Revenue Rights would now receive the auction revenues. The customer could participate in the auction if it wished to retain the Congestion Revenue Rights. We seek comment on whether to allow a transition period before the start of Congestion Revenue Rights auction allocations and, if so, what the length of such a transition should be.

3. Reciprocity Provision

383. In Order No. 888, the Commission included a reciprocity provision in the *pro forma* tariff. Under this provision, all customers (and their affiliates), including non-public utility entities, that own, control or operate interstate transmission facilities and that take service under a public utility's open access transmission tariff, must offer comparable (not unduly discriminatory) services in return.[188] The Commission also recognized that a public utility may deny service simply on a claim that the open access offered by a non-public utility was not satisfactory. Thus, the Commission developed a voluntary safe harbor procedure under which non-public utilities could submit to the Commission a transmission tariff and a request for declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. If the Commission found it to be an acceptable reciprocity tariff, the Commission would require the public utility to provide open access service to that particular non-public utility.[189]

384. We propose to continue this approach to reciprocity. Further, we propose to grandfather all reciprocity tariffs that the Commission previously found met the comparability standards of Order No. 888. We request comment on this proposal.

4. Force Majeure and Indemnification Provisions

385. In Order No. 888, the Commission recognized that the risk allocations regarding liability and indemnification ''must be carefully drafted so that transmission providers and customers can accurately assess and account for their respective risks.'' [190] The Order No. 888 *pro forma* tariff contains a force majeure provision and an indemnification provision.[191] The force majeure provision provides that neither the transmission provider nor the transmission customer will be liable to the other when they behave properly, but unpredictable and uncontrollable force majeure events prevent compliance with the tariff.

386. Under the indemnification provision, the transmission customer indemnifies the transmission provider against third-party claims that arise from the performance of obligations under the tariff. The Commission explained that the purpose of the indemnification provision was to allocate the risks of a transaction, and costs of the risks, to the party on whose behalf the transaction was conducted.[192] Further, as the tariff did not obligate the customer to perform services on behalf of the transmission provider there was no comparable basis for imposing an indemnification obligation on the transmission provider. The Commission found it inappropriate to require the customer to indemnify the transmission provider from damages arising from the transmission provider's own negligence. Thus, a transmission customer is not required to indemnify the transmission provider in the case of negligence or

[187] New York ISO auctions Congestion Revenue Rights and PJM directly assigns Congestion Revenue Rights. MISO has also proposed to initially directly assign Congestion Revenue Rights but to transition to an auction of Congestion Revenue Rights with an allocation of auction revenues to the customers that pay the embedded costs of the system.

[188] *See* Order No. 888 at 31,760; Order No. 888–A at 30,285.

[189] *Id.* at 31,761.

[190] Order No. 888 at 31,765.

[191] *See* Sections 10.1 and 10.2 of the *pro forma* tariff.

[192] *See* Order No. 888–A at 30,301.

intentional wrongdoing by the transmission provider.[193] The Commission further explained that while it was appropriate to protect the transmission provider when it provides service without negligence, the determination of liability in other instances should be left to other proceedings.

387. Since Order No. 888, several entities have sought to revise their open access transmission tariffs to include liability provisions arguing, among other things, that no current federal forum exists for entities that are now subject to Commission jurisdiction only and can no longer seek relief at the state level.

388. We recognize that there may be a need to include liability provisions in the Commission's *pro forma* tariff in circumstances in which there are no liability provisions available in a state tariff; however at this time, we are not prepared to propose a specific provision.[194]

389. We seek comment on the following issues: Is there a need to include liability provisions in the Commission's *pro forma* tariff? Under what circumstances should liability protection be provided in a Commission open access transmission tariff (*e.g.*, should we provide such protection only where it is not available through state tariffs)? If we adopt liability provisions, should they be generic or do they need to be adopted on a regional basis? Should the standards adopted in a Commission *pro forma* tariff reflect what was previously provided under state law? How do we resolve the issue in the multi-state context of an ISO or RTO? The Commission will review the comments filed and then hold a staff technical conference in the fall to further discuss this issue.

I. Market Power Mitigation and Monitoring in Markets Operated by the Independent Transmission Provider

1. Principles and Objectives

390. In a structurally competitive market, one with many buyers and sellers who cannot influence price, the market can assure an overall efficient outcome where prices indicate the value of additional supplies and conservation. The development of structurally competitive markets is the Commission's long-term goal. However, at this stage of the industry's evolution, wholesale electric markets are not yet structurally competitive in all respects. The two significant structural flaws are the lack of price-responsive demand and generation concentration in transmission-constrained load pockets. Given these structural defects, the Commission cannot rely on the interaction of supply and demand in all instances to ensure that prices are competitive and thus just and reasonable.

391. Cost-of-service regulation is not effective for spot market pricing of commodities such as electricity. In the past, customers were served by a monopoly supplier under cost-of-service rates, in which the fixed and variable costs of a company's generation portfolio were allocated over the expected hours of service to determine a cost per kWh. But today, the power needs of load-serving entities are met through a mix of sources, including the companies' generation portfolios, and long-term and spot market purchases from a variety of sellers, including independent producers and marketers. These do not match the long-term arrangements needed for cost-of-service regulation. In this competitive context, cost-of-service regulation designed for long-term cost recovery is not well suited for determining appropriate spot market prices. When applied to spot markets, cost-of-service regulation blunts price signals and leads to inefficient investment and consumption decisions which over the long run increase costs for all customers.

392. When markets do not produce competitive outcomes, the Commission must use new regulatory tools to produce just and reasonable results. We propose new market power mitigation measures to deal with the consequences of major structural defects in wholesale electric markets, by approximating the outcomes that a competitive market would produce. These measures should function in markets that are not workably competitive, but not inhibit market operation in more competitive markets. Effective market monitoring and market power mitigation are critical elements of the Commission's plan to create and sustain competitive regional bulk power markets. Therefore, the Commission proposes rules for the spot markets to be operated by the Independent Transmission Provider to mitigate market power.

393. Market power is the ability to raise price above the competitive level.[195] This can be accomplished if the generator can withhold physical power (physical withholding) or cause physical power to be withheld through inflated bids (economic withholding).[196] Competitive prices over the long run should recover both the fixed and variable costs of efficient generating units. The challenge for market power mitigation on the supply side is to assure that it allows long-term competitive prices, which allows the opportunity to recover the fixed costs of the investment as well as the short-term variable costs of producing electricity. If some degree of scarcity pricing is not allowed, and generation only recovers short-term marginal costs, then some generators needed for reliability could fail to recover their full costs and may be retired. Worse yet, prices could be held so low that investors decline to invest in needed generation, transmission and demand-side projects because they do not see a reasonable expectation of recovering their costs.

394. The market power mitigation measures proposed here are designed to address the major structural defects in wholesale electric markets. The major structural defect on the demand side is the lack of price-responsive demand; when customers cannot respond to high prices by lowering their consumption, they cannot discipline price increases from suppliers. Absent demand response, market prices will reflect

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[193] *See* Order No. 888–A at 30,299–300; Order No. 888–B at 62,080.

[194] We have included the indemnification and liability provisions from the existing *pro forma* tariff in the SMD Tariff pending review of the comments in this proceeding.

[195] The Commission's natural gas pipeline cases have used a definition of market power that examines the company's ability to raise prices significantly above a competitive level for a sustained period. Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 74 FERC ¶ 61,076 at p. 61,230 (1996); and cases cited *id* at n. 52. *See also,* Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 70 FERC ¶ 61,139 at p. 61,403 (1995) (concerning transportation and storage services). These factors recognize that it is difficult to identify market power with precision, both because it is difficult to precisely identify the competitive price (which should recover both fixed and variable costs over the long run) and because it can be difficult to isolate the impact of one entity on the competitive price. These factors also recognize that there is an implicit cost/benefit assessment to decisions to intervene in the exercise of market power. The cost of intervention in transient price increases could be greater than the public benefit gained by the intervention. Commission decisions about when to intervene in an exercise of market power are important, but need to be tailored to the circumstances of the product and the industry. In the electric industry, electricity prices can spike for one hour or a few hours in ways that are less likely for natural gas pipeline transportation and storage rates, and the consequences can be quite different. Since the definition of market power and the decision when to intervene in its exercise are analytically distinct issues, in this rulemaking the Commission incorporates the concept of when to intervene in an exercise of market power into the choice of triggers for the market power mitigation mechanisms, rather than in the definition of what constitutes market power.

[196] Market power can also be exercised by creating barriers to entry so other suppliers cannot reach the market or by causing other supplier's production costs to increase.

suppliers' bids alone, so we cannot rely on market prices to ration scarce supplies in all situations. Therefore, the market power mitigation needs to compensate for the lack of price-responsive demand in the market.

395. On the supply-side, structural problems tend to be more location-specific and time-dependent. For example, binding and sometimes unpredictable transmission constraints may restrict competitive alternatives and create opportunities for some sellers to increase prices above a competitive level, at least for any seller that knows some of its output will be required to meet load reliably. This problem is often described as a load pocket problem. In some load pockets, a specific generator may be identified as needed for reliability, which gives it a local monopoly.[197] In other situations without severe constraints, the geographic market may be broader but if little generation divestiture or entry by non-affiliated generators has occurred, concentration of ownership may remain high. Market power mitigation needs to mitigate local market power, whether it arises because of a load pocket, transmission constraints, or ownership concentration.

396. To be effective, market power mitigation measures must be applied before the fact, since remedies after the withholding has occurred are disruptive to the market and increase regulatory risk to its participants, which increases costs to customers.

397. In sum, the challenge in developing an effective market power mitigation plan is to design a plan that allows markets to function where they are competitive and, where they are not, uses market mechanisms to facilitate the transition to competitive markets. Market mechanisms can be used to approximate the outcomes that a competitive market would produce to provide the price signals for efficient investment and demand response. Because of the characteristics of electricity (it can be stored only in limited instances—pumped storage, compressed air, batteries) and the electric grid (flows follow the path of least resistance), even in regions where markets are generally competitive, transmission constraints may create non-competitive conditions during certain hours. In addition, when market power exists, the market power mitigation plan should be calibrated so that it does not inefficiently suppress prices, or mask scarcity prices, providing the wrong economic signals for efficient investment or demand response.

[197] This is also true for certain types of ancillary services (*e.g.,* reactive power) where specific generators may have the ability to exercise market power because of their location.

2. Overview of the Market Power Mitigation Measures

398. The Commission proposes a market power mitigation plan composed of three mandatory components that are specifically tailored to the structural flaws in the wholesale electric markets and a voluntary fourth measure that could apply in unusual market conditions to assure that the high prices are not the result of market power.

399. The first measure addresses the local market power problem and is similar in concept to the reliability must run agreements that exist in the ISOs today. The market monitor will identify certain conditions in which certain generators are in concentrated geographic markets created by transmission congestion or reliability needs of the grid. These would include units needed to run to support the reliable operation of the grid or a set of units owned by a small number of companies. At those times, those units will have localized market power so that when they are required to provide their energy or ancillary services to the grid their bids into the market should be capped.[198] The conditions when their power must be supplied to the grid (a must-offer obligation) and the bid cap to apply would be specified in their participating generator agreement with the Independent Transmission Provider.

400. The second component, a safety-net bid cap such as the $1000 per megawatt-hour cap currently used in Northeast markets and Texas, addresses the lack of price-responsive demand. Sellers could freely offer any amount of energy to the spot markets constrained only by the safety-net bid cap. The safety-net bid cap should allow markets to produce prices that reflect some (and perhaps a significant) amount of scarcity when shortages of reserves or power exist. But absent demand response, it sets an outer bound on suppliers' ability to exercise economic withholding.

401. The third component of the market power mitigation plan is the resource adequacy requirement discussed in Section J. The resource adequacy requirement does not directly prevent withholding, but by expanding the resource alternatives it diminishes the incentive and the ability of suppliers to practice and profit from either physical or economic withholding.

[198] This would include a broader group of units than what are often referred to as reliability must run units.

402. While it is clear that the first three measures must be part of the Standard Market Design market power mitigation plan, there may be market conditions in which a fourth measure is needed. The fourth mitigation measure would deal with situations when non-competitive conditions may exist, by examining and possibly limiting bids from individual suppliers into the day-ahead and real-time spot markets if those bids are high due to withholding rather than scarcity. Exercise of this mitigation could be triggered by predetermined conditions or triggers (such as a sustained period of prices significantly above competitive levels), or by significant infrastructure problems in the market (*e.g.*, sustained tight reserve conditions, as might be due to drought). This mechanism is like the Automatic Mitigation Procedure (AMP) used by the New York ISO, and adopted recently for the California ISO. This mechanism would not be required for every region but may be adopted if the market monitor's analysis determines this measure is needed.

403. The implementation of the market power mitigation plan summarized above and described in more detail below will rely on the results of an initial competitive market analysis by the Independent Transmission Provider's market monitor in each region. This will identify at the outset the persistent load pockets or other conditions that create local market power. This analysis will be filed with the Commission as part of the implementation process for Standard Market Design and subject to comment from all interested parties. After Commission review, it will form the basis for the mitigation measures that are applied by the Independent Transmission Provider. It then will be updated annually to review the continuing effectiveness of the market power mitigation.

404. The market power mitigation measures proposed rely principally on mitigating market power in spot markets. Mitigation would only apply to products traded in the spot markets operated by the Independent Transmission Provider, not to products traded under bilateral contracts outside the Independent Transmission Provider's spot markets. This is the least intrusive framework for market power mitigation but at the same time provides very effective protection against market power.

405. Although power and operating reserves purchased in the organized spot market are only a small percentage of total purchases, mitigating the organized spot market is an effective

way of mitigating market power generally.[199] Bilateral contracts generally reflect buyer and seller expectations of prices in spot markets. Therefore, market power mitigation in the organized spot market will effectively discipline market power in bilateral markets as well.[200] However, if spot market prices are over-mitigated, it may weaken incentives for buyers to contract in bilateral markets and expose spot market prices to greater price volatility. Regular reassessment of the market power mitigation practices can prevent this outcome, and, as discussed *infra*, the market monitor will be required to annually reassess the effectiveness of the market power mitigation.

3. Market Power Mitigation for Local Market Power

406. Local market power principally arises either from the concentration of generator ownership within a load pocket, or the need for local units to operate to assure system reliability and stability within the load pocket. Local market power can arise from both persistent and foreseeable congestion, or from sporadic transmission congestion. Although local market power can arise from these different conditions, the mitigation method proposed here can be effective at mitigating the local market power regardless of how it arises.

407. In the existing ISOs in California and the Northeast, participating generator agreements are used to set out the operating terms, conditions and obligations concerning the dispatch of a generating unit, serving principally a reliability purpose. Under the Standard Market Design *pro forma* tariff all generators dispatched by the Independent Transmission Provider would enter into a participating generator agreement.[201] Standard Market Design will require these participating generator agreements to include provisions to mitigate local market power.

408. The participating generator agreements, which would be filed with the Commission, would identify the non-competitive conditions when the generator with local market power would be required to offer its energy either by scheduling a bilateral transaction or by offering all available energy to the spot markets. This would be a must-offer requirement. The requirement would apply when the generator's power is needed to maintain the reliable operation of the grid, and also when there are insufficient competitive alternatives. The participating generator agreement would specify the conditions that would give rise to a generator's must-offer requirement, and would also specify bid caps that would apply when the generator was required to bid into the day-ahead and real-time markets. In non-competitive conditions, the generator's bids could not exceed the capped values. Although the participating generator agreement may restrict a generator's energy and operating reserves bids, the generator would still receive a market-clearing price and additional revenue to cover start-up and no-load costs.[202] The capped bid could also set the market clearing price.

409. In addition to the bid caps specified in the participating generator agreements, local market power also will be limited through bilateral contracts between load-serving entities and the generators. Under the resource adequacy requirement, load-serving entities must have enough resources to meet their demand to ensure the reliability of the grid. It can be expected that some of those resource requirements will need to be fulfilled with contracts with generators within their load pocket to ensure that the resource is deliverable during peak or congested periods. Bilateral contracts are an effective way for a buyer to mitigate the market power of a seller.[203] The load-serving entities can be expected to include provisions in these contracts specifying when a generator must run to meet any reliability needs in that location and the price to be paid. Whenever a generator is scheduled to run under a bilateral contract, this will fulfill its must-offer obligation in the participating generator agreement with the Independent Transmission Provider.

410. Under the participating generator agreements, when conditions are not competitive, that is, when there are insufficient alternatives available to meet load in that location, a generator must run to provide all its available capacity to the grid, either by scheduling a bilateral transaction or bidding into the spot market. The need for the generator to be producing could be identified either in the day-ahead market based on projected system conditions or in real time. In the day-ahead market, all available capacity would include all capacity not sold bilaterally and scheduled or on an outage. In the real-time market, all available capacity would include all non-producing capacity (not delivered to the market) *i.e.*, capacity not on a planned or forced outage.[204]

411. The Commission invites comment on how to structure the local market power mitigation, particularly on how to define the noncompetitive conditions which should trigger the mitigation, and on how bid caps should be structured for generators operating under a participating generator agreement.

412. There are some options for dealing with the risk of a forced outage inside a load pocket. One is for a portion of available day-ahead capacity to be exempt from the bid-in requirement to reflect forced outage risk in real time. Another possibility is to allow generators to provide all available capacity in real time at a capped bid in lieu of bidding in the day-ahead market to accommodate generators that have significant risk or opportunity costs. A third option would vary depending on whether the generator receives a reserve capacity payment. If the generator receives a capacity payment, that payment compensates for the outage risk so the generator should be obligated to deliver energy or to pay for substitute supply from some other source. If the generator does not receive a capacity payment, then it should not have to bear the risk for a legitimate outage. Units declaring a forced outage would be subject to audit by the market monitor. If the outage is found to be unjustified, then the generator should be subject to a penalty. The Commission requests comment on the penalty that would be appropriate to deter unjustified forced outages.

4. The Safety-Net Bid Cap

413. If bid-in capacity is generally insufficient to meet both operating reserve requirements and load, capacity rights associated with the resource adequacy requirement may be exercised by load-serving entities that have secured sufficient capacity so that they will not be interrupted. However, in this situation, lack of demand response can

[199] Stoft, Steven. *Power System Economics.* New York, NY: Wiley-IEEE Press, 2002, Section 2–4.5, ''How Real-Time Price-Setting Caps the Forward Markets,'' p. 150.

[200] Relying on mitigating market power in the spot market has been an effective mitigation method in the New York ISO under its AMP, and the California ISO since May, 2001.

[201] SMD Tariff Section A.9.2.

[202] SMD Tariff section F.1.11. The generator's legitimate minimum run times would also be honored under the provisions of SMD Tariff section F.1.5.

[203] *See* Comment of the Staff of the Bureau of Economics and the Office of the General Counsel of the Federal Trade Commission, Docket No. RM01–12–000 (July 23, 2002).

[204] Under the Standard Market Design tariff, all units scheduled day ahead under a must-offer obligation, but not needed in real time would get paid their start-up and no-load costs.

result in dramatic increases in market-clearing prices, even with comprehensive mitigation on the supply-side, *if* imports can bid in at unrestrained levels. In this case, imported power from adjacent markets could set a market-clearing price above the marginal cost of the highest cost unit dispatched within the market.[205]

Current markets in the Northeast and Texas rely on a $1000 per megawatt-hour bid cap, regardless of market conditions, as a safety-net that may be binding in this situation. The Commission proposes to adopt a safety-net bid cap as part of the market power mitigation plan here. Under this proposal, no bid to supply can exceed this level, regardless of cost or risk or location, even if the market is confronted with a genuine operating reserve shortage. However, if the monitor establishes that some units may provide power at a cost that exceeds the safety-net, a higher price for those units would be justified. In California, for example, imports are not allowed to set the market clearing price. However, in the market power mitigation framework proposed here imports would be allowed to set the market clearing price in order to get a proxy for a scarcity price, up to a capped value. If requirements cannot be satisfied with bid-in imports that would be subject to the safety-net bid cap, then load that has not met its resource adequacy requirement should be penalized as described in the Resource Adequacy section. A safety-net bid cap, such as the $1000 per megawatt-hour cap in the Northeast and Texas, can serve as a proxy scarcity price under Standard Market Design. The Commission requests comment whether the safety-net bid cap should be uniform across an interconnection, so that there would be one cap applicable in the East and another applicable in the West.

414. Comment is requested on how to determine an appropriate value for such a cap. It is important to examine the implicit trade-off between bilateral capacity payments, the safety-net bid cap and local market power mitigation. That is, a bid cap that constrains scarcity prices would be expected to translate into higher bilateral capacity payments under a contract to fulfill the long-term resource adequacy requirement. With a higher safety-net bid cap, perhaps one based on the value of lost load, smaller bilateral capacity payments would be required to maintain the same level of resource adequacy in the absence of price.

5. Mitigation Triggered by Market Conditions

415. The Commission proposes a fourth voluntary market power mitigation measure which may be recommended by the market monitor during the Standard Market Design implementation process, or any time thereafter. This measure, if needed, would apply to unanticipated and sustained market conditions that would give the ability and the incentive to exercise market power. For example, extreme supply or demand conditions to which the market cannot quickly adapt, such as the loss of significant hydropower capacity because of drought, or force majeure events such as a major transmission line outage. These kinds of events, which are not transitory, can provide opportunities to exercise market power even in a market that is normally workably competitive. It may be appropriate for other conditions to trigger this mechanism. We seek comment on what these triggers should be. Although market-clearing prices would be expected to rise in these situations, and perhaps sharply and significantly, it may be important for the market to have the assurance that the price increases are attributable to the extreme circumstances and not to the exercise of market power. An AMP mechanism such as those approved by the Commission in New York ISO and California could provide this kind of assurance.[206]

416. This kind of mechanism may not be necessary in every region. If a market monitor proposes such a mechanism, the proposal must include the specific triggers that would be used to initiate this form of market power mitigation along with the details of the mitigation method. Since this form of market power mitigation is for temporary market conditions, it will be equally important for the market monitor to indicate the criteria to determine when the market has returned to normal competitive conditions and this market power mitigation method will be suspended.

417. The details of this market power mitigation method, including the triggers, would be set out in the Independent Transmission Provider's tariff. If market conditions developed that satisfied the pre-determined triggers for the mechanism, it would be the market monitor's responsibility to give notice to the public and the Commission that the tariff mechanism had been triggered. The mechanism would then automatically take effect until the conditions developed that satisfied the pre-determined triggers for the suspension of this market power mitigation mechanism. If a market monitor proposes to use this form of market power mitigation, the details of the mechanism and the triggers would be subject to comment by all interested parties, and review by the Commission.

6. Establishing Bid Caps or Competitive Reference Bids

418. The mitigation for local market power, through the participating generator agreements, relies on must-offer obligations to mitigate physical withholding and bid caps to mitigate economic withholding. Mitigating economic withholding entails determining appropriate bid caps for all bid-in parameters.[207] The unit-specific bid caps in the participating generator agreements serve as proxy competitive bids for energy, regulation service, and operating reserves, and for other unit-specific operating parameters such as minimum run times and high and low operating levels. Bid caps should reflect the marginal cost—including opportunity cost—of offering all capacity, including power that may be supplied only under limited conditions. Other bid-in parameters should reasonably reflect operating conditions consistent with good engineering practice under competition.

419. The development of bid caps, especially for generators with significant opportunity costs such as hydropower and energy-limited units, is difficult and can be controversial. Nevertheless, this mitigation plan would require that each generator, including hydropower and energy-limited units, that may have local market power would need to have an agreement establishing bid caps for all bid-in parameters if its power is needed for the grid or local market power mitigation is necessary.

420. The Commission has approved several options for setting default energy bids that in some circumstances serve as energy bid caps. They include: (1) Default bids based on various averages of previously selected in-merit bids; (2) default bids based on various cost measures, usually a measure of operating cost adjusted for fuel costs;

[205] Generators outside the region would not have participating generator agreements with the Independent Transmission Provider, with provisions for addressing local market power, and neither would marketers.

[206] *See* California Independent System Operator Corp., 100 FERC ¶ 61,060 (2002). *See* New York Independent System Operator, Inc. *et al.,* 99 FERC ¶ 61,246 (2002). Although AMP was in effect in all of New York, it was only triggered on four occasions, reflecting conditions in eastern New York.

[207] These same considerations would apply if the Commission adopted an AMP-like mechanism with bid caps or competitive reference bids.

and (3) default bids agreed through contract or negotiation. For many fossil-fired units, an estimate of operating costs plus a margin, such as ten percent, could provide a reasonable bid cap for a unit's energy bid when competitive forces cannot be relied on, similar to PJM's approach for mitigating reliability must run units.[208] Although fossil-fired units may have opportunity costs not fully reflected by operating costs, an adder, such as that used by PJM, is one way to allow flexibility to respond to these uncertain costs. The Commission requests comment on whether the level of the adder should be reviewed on a region-by-region basis or if the Commission should establish a uniform adder, and if so, at what level.

421. For peaking units that are likely to set market clearing prices when they are dispatched, the must-offer requirement coupled with mitigation that sets bid caps at marginal cost could result in revenues that fail to recover fixed costs over a reasonable period of time. Although such units may recover additional revenue in capacity and reserves markets, bid caps for these units could also reflect a ''scarcity'' premium or adder to compensate for the lack of price-responsive demand that would otherwise set the price when these units were dispatched. The average cost of a new peaking unit at a given location operated over a given number of hours could form the basis for setting such a premium. This kind of adjustment to bid caps for peaking units could help support reliability until demand-side measures for responding to price were more fully incorporated in markets. The Commission requests comments on whether this approach or other adjustments to bid caps for peaking units might usefully substitute for demand response in the near term.

422. For hydropower and other energy-limited resources much of the difficulty in determining an appropriate energy bid cap for these units comes from the difficulty of assigning a value to their temporal opportunity costs. However, the times when it would be necessary for the transmission provider to call on power from these sources are likely to be times when prices are high and these units would want to be scheduled in any event. At all other times, hydropower units, in particular, should be offering all available capacity as operating reserves since their marginal operating costs are close to zero, but they may have high temporal opportunity costs. In other words, there appears to be no economic reason why such units should not always be fully committed either to the bilateral market or spot markets for operating reserves. Consequently, it appears unnecessary to cap energy bids from such resources below the safety-net bid cap as long as their bids to provide operating reserves were always in-merit. Alternatively, other energy-limited resources might be allowed to submit a bid that states a total megawatt-hour availability over the day and allow the market operator to schedule the power from the unit in the hours when the price is highest. Comment is requested on these and other approaches to establishing reasonable caps for energy bids.

423. Another alternative for hydropower, and other energy-limited resources, would be for the unit operator to submit a seasonal or monthly schedule for when the unit would not be expected to operate. This would enable, for example, hydropower units to specify the periods when they would expect to need to preserve water or flow water to satisfy environmental conditions. While these units have many legitimate competing needs for the water flow, it is still possible for a hydropower generator to engage in physical or economic withholding. In the existing ISOs, generators must submit a schedule for planned outages, which is coordinated by the ISO to ensure that outages occur when they are the least disruptive to the markets. The Independent Transmission Provider is expected to continue to perform this outage coordination function under Standard Market Design. Scheduling outages in advance, coupled with auditing by the market monitor, would provide a way to evaluate whether failures to run were from withholding or legitimate limitations. For hydropower units, for which the marginal costs are primarily opportunity costs, this method may be a sufficient check against withholding so that it might be unnecessary to have a bid cap for these units. The Commission requests comment on these alternatives.

424. Any parameters that a generator may include in its bid may require a cap or other restraint. For example, PJM caps regulation service at $100 per megawatt-hour, and New England uses energy prices to cap prices for spinning reserves. Standard Market Design would also allow availability bids for these products. The participating generator agreements should also contain bid caps for these operating reserves when they are needed for the operation of the transmission system and non-competitive conditions exist. However, the Commission requests comment on how to identify the options for determining competitive bid caps for regulation service and operating reserves, including availability bids, that should be established for day-ahead and real-time markets.

425. In the New York and PJM day-ahead markets, the unit-specific energy bid cap applies to the day-ahead market where separate bids for start-up and no-load costs are also available and would also be available under Standard Market Design. Market power mitigation should also establish caps for these bids and a variety of bid-in operating parameters, such as low and high operating levels and minimum run times, if non-competitive circumstances would permit sellers to manipulate these parameters to get unjustified higher up-lift payments. PJM, for example, does not mitigate the start-up and no-load bids or certain operating parameters, but it only allows units to change these values once every six months. New York permits greater flexibility and uses various screens to assess whether a seller is behaving non-competitively and should be mitigated.

426. Several approaches could be used for establishing bid caps for these particular parameters. One possibility would be to rely on engineering data, such as from the manufacturer about the specific type of unit, to establish caps for start-up and no-load bids and certain operating parameters, and give generators the flexibility to bid within those ranges without mitigation. These ranges would also be included in the generators' participating generator agreements. Just as with energy bids, a bid above the range *could* be mitigated *if* the bid raised market-clearing prices or uplift payments above a competitive benchmark level by a significant amount. Because factors that might cause generators to modify start-up and no-load bids and parameters such as minimum run times generally are thought to be less variable than factors that may influence energy bids, caps for these variables may be quite tight.[209] In fact, PJM's approach to permit changes to these parameters once every six months may be a simpler alternative that does not unduly restrict competitive generator behavior. Comment is requested on this approach and on other ways to prevent sellers from manipulating these bids and operating parameters to increase market-clearing prices and uplift payments.

[208] This method may not work for fossil-fired units that are only permitted to run a limited number of hours due to environmental restrictions. These energy-limited resources are discussed below.

[209] For example, energy prices could change frequently because of differences in the cost of fuels such as natural gas.

427. In the implementation filing, the market monitor would propose tariff language that sets forth the process for setting the bid caps for individual units or any formulas that might be used for this purpose. The market monitor would be responsible for collecting and verifying data from these units to establish appropriate caps for energy bid values consistent with the procedures in the Independent Transmission Provider's tariff. This could be controversial, especially for generators in load pockets that may effectively face ''mitigation'' in most situations. The Commission requests comment whether the Commission should establish a formula for determining the bid caps or whether the Commission should review the proposals developed in each region.

7. Exemptions

428. It is appropriate to exempt certain sellers from the market power mitigation. Specifically, sellers who control a small amount of capacity in the market, for example no more than fifty megawatts, would be exempt from mitigation. Sellers with little capacity would have little incentive to exercise market power since a non-competitive bid could eliminate their only unit from the dispatch. However, the Commission requests comment whether any other sellers should be exempt from the mitigation because they have insufficient incentives to withhold.

8. Monitoring

429. Market monitoring should be conducted on an on-going basis by a market monitoring unit that is autonomous of the Independent Transmission Provider's management and market participants. The market monitoring unit may be located within the offices of the Independent Transmission Provider, to permit easy access to the market data and operations personnel, or it may be physically located elsewhere.

430. The market monitor will be expected to report directly to the Commission, and the independent governing board of the Independent Transmission Provider. This will include reporting at regular intervals on the general performance of the markets in its region and reporting, on a timely basis, observed attempts at market manipulation or factors that impair the efficiency of the market. Although the market monitor will be accountable only to the Commission and the governing board, it should share its analyses and reports with the management of the Independent Transmission Provider and the Regional State Advisory Committee. This will enable the committee to carry out its advisory functions in an informed manner.

431. The market monitor must focus both on the functioning of the markets run by the Independent Transmission Provider as well as the conduct of individual market participants. The market monitor should focus on identifying factors that might contribute to economic inefficiency. Such factors include market design flaws, inefficient market rules, entry barriers to new generation, including distributed generation, barriers to demand-side resources, transmission constraints and market power. In monitoring for exercises of market power, the market monitor should focus principally on detecting economic and physical withholding (as distinct from the normal operation of supply, demand, and true scarcity). For entities that own both transmission and generation assets, withholding behavior could include both generator and transmission outages. For example, instead of directly withholding a generator's power, a market participant with transmission assets could effect the same end by derating a transmission line needed to deliver the generator's power to the market. Monitoring should be designed to detect this kind of behavior.

432. The Commission requests comment on whether the market monitor should also be responsible for monitoring the Independent Transmission Provider's operations, in addition to the markets and the market participants. Specifically, should the market monitor evaluate whether the Independent Transmission Provider treats market participants neutrally, without undue discrimination?

433. To meet its responsibilities, the market monitor must have the ability to collect and evaluate necessary data provided by the Independent Transmission Provider and market participants. The market monitor would have the responsibility to propose to the Commission, and the Independent Transmission Provider's board changes to market rules, if they provide inefficient incentives to market participants, and to promptly identify circumstances that may require additional market power mitigation so that remedies can be put in place prospectively.[210] The market monitor would also be required to provide a comprehensive analysis and report of market structure and individual generator conduct in the spot markets, at least annually, to evaluate the overall efficiency of spot market operations, the market for Congestion Revenue Rights, and how the balance between resources and demand in the region affects the market's ability to efficiently serve load at least cost. In addition, the market monitor must also annually assess the effectiveness of any mitigation actions taken and review the terms, conditions, and bid caps in the participating generator agreements. Finally, the market monitor must engage in surveillance to insure that market participants comply with the rules in the Independent Transmission Provider's tariff.

434. The work and findings of the market monitor must be integrated into the regional planning process. The market monitor's analysis of the markets will identify load pockets and can help provide direction for needed investment in generation, including distributed generation, demand response capability, and transmission infrastructure to improve the competitive structure of the markets.

435. The Commission proposes here the basic elements of a market monitoring plan to be used by each market monitor. The Commission staff will convene a conference in the Fall to discuss and further develop the essential elements that should be required in a standard market monitoring plan. After getting additional public input at the conference, Staff may propose additional detail for the market monitoring plan, which the Commission may adopt, after an opportunity for public comment.

a. Framework for Analyzing Market Structure and Market Conduct

436. The Commission intends to require the use of a core set of questions and analytical techniques to be used by each market monitor to assess market structure, participant behavior, market design, and market power mitigation. This will facilitate inter-regional comparisons. Examining this core set of issues using techniques reflecting ''best practices'' would be an essential part of the monitor's responsibilities that allows inter-regional comparisons. However, specifying these core requirements here should not prohibit or discourage monitors from expanding their analyses where regional differences or unanticipated events warrant it. In fact, because markets and monitoring are in a formative stage, the Commission would need to continue to facilitate communication between market monitors to share insights and develop common approaches.

437. An important focus of market monitoring will be structural market

[210] The changes would only go into effect after Commission approval.

conditions since the Commission's ultimate goal is to foster structurally competitive regional bulk power markets. Academic analysts and market monitors have examined the competitiveness of current spot markets using various approaches and data. Some have focused on developing a simulated competitive benchmark that can serve as a reasonable measure of the market's overall efficiency.[211] Others have examined whether specific generator bidding behavior has been consistent with profit maximization under competitive conditions.[212]

438. Some monitors have estimated whether average generator profitability would cover costs of a gas-fired peaking unit and provide sufficient inducement for entry.[213] Most monitors also track bidding patterns so that sudden, inexplicable changes can be investigated promptly to evaluate whether market power is a cause of the change.[214] Monitors also track changes in concentration, unplanned generator and transmission outages, and changes in various operating parameters that may signify market power problems.[215] Although the reports have been very useful in enhancing our understanding of a wide range of issues, the approaches have been varied, key questions have been framed differently and, importantly, the markets have not had the same design. As a consequence, results have not been comparable across markets. With the widely varying market designs of the past, greater comparability across regions was not feasible. However, these analyses have served as a useful starting point for developing a standard analytical framework.

439. The Commission proposes to require each monitor to perform a structural analysis of the region that would include: (1) Market concentration including by type of generation, (2) conditions for entry of new supply, (3) demand response, and (4) transmission constraints and load pockets that give sellers the ability and incentive to exercise market power. This analysis would be performed prior to the implementation of the Standard Market Design, in order to implement the market power mitigation. It also would be performed annually to reassess and adjust the market power mitigation, and to evaluate the conditions of the market.[216]

440. In addition, the Commission proposes to require an annual assessment of the performance of the markets operated by the Independent Transmission Provider. This assessment would use a competitive benchmark to assess market performance as an additional means of assessing the effectiveness of the market power mitigation.

441. Comment is requested on how the monitor should address these and other topics, to develop useful measures that permit inter-regional comparisons. For example, concentration measures stratified by generator type might better identify competitive alternatives under various demand conditions. Estimates of generator profitability, such as PJM and ISO-New England have used in the past, might be a useful measure of incentives for generator entry. These estimate the degree to which a hypothetical unit operating in all profitable hours would have recovered its costs. Although it is not a definitive profit estimate for any particular generator, it may be a useful measure for comparing incentives for generator entry across market or regions.

442. A core set of questions and analytical techniques must also be developed for monitors to use to evaluate conduct of market participants in the transmission and spot markets operated by the Independent Transmission Provider. Analysis of generation and transmission outages is central because these can be forms of withholding. Because some owners of generation also own transmission, monitors must review any planned transmission outages, for example, to make sure that scheduling outages could not be used to enhance or create opportunities to exercise generator market power. Analysis of generator conduct might also include a review of bidding behavior in the spot markets operated by the Independent Transmission Provider to identify any auction design flaws that may give market participants an unanticipated incentive and ability to manipulate market-clearing prices or up-lift payments. The monitor should also evaluate the effectiveness of the participating generator agreements in mitigating market power where market structure is not sufficiently competitive.

443. Finally, the monitor must analyze the operation of the congestion management system and the market for the resale of Congestion Revenue Rights for evidence of market power or manipulation. The monitor must also assess whether those who collect congestion revenues are in a position to influence transmission expansion plans that can affect congestion revenues and report on the incentive structure of those arrangements.

444. Any flaws in the market rules that may be identified by the monitor and any market participant conduct that indicates the ability to exercise market power under the market rules in effect would be remedied prospectively after Commission authorization of changes to the market rules. However, if the conduct violates existing rules, the market monitor must have the necessary tools to investigate the conduct and to penalize it. These will be discussed in the sections below.

445. An important adjunct to the market power mitigation and monitoring plan will be a clear set of rules governing market participant conduct with the penalties for violations clearly spelled out. The Commission proposes to require the Independent Transmission Provider to include in its tariff certain minimum behavioral rules, which will be monitored by the market monitor. These will include, at a minimum, the following rules:

(1) *Physical Withholding:* Entities may not physically withhold the output of an Electric Facility (Generating unit or Transmission Facility) by (a) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, or (b) failing to comply with the must-offer conditions of a participating generator agreement.

(2) *Economic Withholding:* Entities may not economically withhold by submitting high bids that are not consistent with the caps specified in the tariff or the participating generator agreements.

(3) *Availability Reporting:* Entities must comply with all reporting requirements governing the availability and maintenance of a Generating Unit or Transmission Facility, including proper Outage scheduling requirements. Entities must immediately notify the Independent Transmission Provider when capacity changes or resource limitations occur that affect the

[211] *See, e.g.*, Borenstein, S., J.B. Bushnell, and F. Wolak (1999). ''Diagnosing Market Power in California's Deregulated Wholesale Electricity Market.'' POWER Working Paper PWP–064, University of California Energy Institute, *available in http://www.ucei.berkeley.edu/ucei/pwrpubs/pwp064.html*.

[212] Joskow, P.J., and E.P. Kahn (2001). ''A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000.'' NBER Working Paper No. W8157. National Bureau of Economic Research.

[213] *See, e.g.*, PJM Interconnection State of the Market Report 2000.

[214] *See, e.g.*, New York Market Advisor Annual Report on The New York Electricity Market for Calendar Year 2000, by David B. Patton, Ph.D., Capital Economics, April, 2001.

[215] *See, e.g.*, Annual Market Report, May 2000–April 2001, ISO New England, August 1, 2000.

[216] The monitor should particularly pay attention to concentration in the regulation and operating reserves markets, and consider the amount of supply relative to demand, and propose specific market power mitigation measures for these markets if necessary.

availability of the unit or facility or the ability to comply with dispatch instructions.

(4) *Factual Accuracy:* All applications, schedules, reports, or other communications to the Independent Transmission Provider or the Market Monitor must be submitted by a responsible company official who is knowledgeable of the facts submitted. All information submitted must be true to the best knowledge of the person submitting the information.

(5) *Information Obligation:* Entities must comply with requests for information or data by the Market Monitor or the Independent Transmission Provider that are consistent with the tariff.

(6) *Cooperation:* Entities must assist and cooperate in investigations or audits conducted by the Market Monitor.

(7) *Physical Feasibility:* All bids or schedules that designate resources must be physically feasible within the limits of the resource, *i.e.*, the resource is physically capable of supplying the energy, ancillary service, or demand response needed to fulfill a schedule or bid according to the physical limitations of the resource.

446. These rules must be accompanied by predetermined penalties, as discussed below in the Enforcement section.

b. Data Requirements and Data Collection

447. Data collection should be targeted to providing monitors with information necessary to answer the required questions covering critical issues regarding market structure, participant behavior, and market design. These data would be acquired from various public sources and in the normal course of operating the markets. They would include: (1) Market statistics and indices, such as market-clearing prices and system-wide congestion costs; (2) data on system conditions, such as transfer capability and planned and forced outages; (3) information on other prices, such as fuel prices and prices in adjacent markets; (4) information on load served from the spot market; (5) data relating to generator bidding patterns; and (6) information on Congestion Revenue Rights.

448. In addition, monitors must have the ability to obtain data on generator production and opportunity costs and information on the operating status of transmission and generation facilities that relate to claimed outages or deratings. Generator-specific data on all relevant costs and operating parameters—*e.g.*, start-up, no-load, environmental, fuel, maintenance, ramp rates, low and high operating levels, and heat rates—may also be relevant to establishing appropriate bid caps for participating generator agreements. These data when combined with information acquired in the normal course of business operations and schedules for planned outages should give monitors the information they need to fully analyze the competitiveness of the markets operated by the Independent Transmission Provider.

449. As a condition for participating in the spot markets, and using the transmission grid, market participants must agree to provide the market monitor with any information requested. Since the ability of the market monitor to perform his or her monitoring role is dependent upon the ability to acquire the necessary information, the monitor must have the ability to require market participants to provide information. This is an important enforcement tool. The Independent Transmission Provider's tariff should specify the penalties that would apply to market participants who fail to comply with an information request from the market monitor. Market participant objections to market monitor information requests will be resolved by the Commission on an expedited basis because delays in providing information could result in continuing harm to the market. In any such dispute the Commission will give substantial deference to the market monitor's stated need for the information.

450. All information obtained by the monitor that is specific to a market participant would be treated confidentially. Any disputes concerning how the confidential information could be used would be resolved by the Commission, before the data are released to the public. Since the Commission has oversight responsibility for wholesale electric markets, any data collected by the market monitor would be available to the Commission and the confidentiality of the data would be protected by the Commission under its regulations.

c. Reporting Requirements

451. At a minimum, the monitor would be required to submit an annual report to the Commission and the Independent Transmission Provider's governing board, and share that report with the Regional State Advisory Committee. The report would include: (1) A general description of the market operations, supply and demand, and market prices; (2) an analysis of market structure and participant behavior following guidelines described above; (3) an evaluation of the effectiveness of mitigation measures taken; (4) an overall assessment of market efficiency perhaps using a simulated competitive benchmark as some have developed; (5) an evaluation of barriers to entry for generating, demand-side, and transmission resources; and (6) any recommended changes to market design or market power mitigation measures to improve market performance. The report would also include a discussion and analysis of any region-specific issues that the monitor judges important to achieving a competitive outcome. This could also be particularly useful to the planning process in determining where expanded transmission capacity might reduce market power problems in load pockets. The annual report would be made public, with appropriate protections to maintain confidentiality, if necessary.

452. In addition, the market monitor will be required to report to the Commission, through the Office of Market Oversight and Investigation, any instances of conduct by market participants that appear to be inconsistent with the Independent Transmission Provider's tariff. Early reporting of questionable conduct will permit coordination between the market monitor and the Commission's investigative staff to determine the best methods for developing the facts and addressing conduct that could be harmful to the market.

453. The Commission requests comment whether additional reporting requirements are needed.

d. Enforcement of the Tariff Rules

454. The market monitor must play an important role in the enforcement of the market rules contained in the Independent Transmission Provider's tariff. In this role the market monitor will need to coordinate closely with the Commission's investigative and enforcement staff. However, to ensure effective enforcement, the market monitor must have adequate authority to investigate market participant conduct and the Independent Transmission Provider must have a set of predetermined penalties to apply to conduct that is in violation of the rules of the Independent Transmission Provider's tariff.

455. As a condition of participating in the markets operated by the Independent Transmission Provider and using the transmission grid operated by the Independent Transmission Provider, the Commission proposes to require market participants and transmission customers to agree to predetermined penalties that would apply to violations

of the tariff rules. Since the tariff rules are intended to ensure the fair and efficient operation of the markets, the penalties should be designed to deter conduct that is inconsistent with the fair and efficient operation of the markets. Specifically, the penalties should deter conduct that results in an economic benefit derived from a violation of the rules. The penalties should, at a minimum, require payment of the economic benefit derived by the violator from violating the rules. Where the violation could result in conduct that could be harmful to the reliability of the grid, it would be appropriate for the penalty to be significantly higher to serve as a deterrent for the conduct. The Independent Transmission Provider's tariff must specify the conditions that would apply for each level of penalty.

456. It may be appropriate to build into the tariff standards for mitigating the penalty. Some standards that could be used are: the impact on the operation of the grid, the financial impact on the violator, and any good faith efforts to maintain compliance. The Commission requests comment on the conditions that would justify mitigation of the penalty.

J. Long-Term Resource Adequacy

457. To operate the transmission system reliably, the transmission operator must be able to balance generation and load at all times. This requires adequate electric generating, transmission, and demand response infrastructure. Some lead time is needed to develop adequate infrastructure for the future through self supply or bilateral contracting.

458. Resource adequacy today must be assessed at the regional level. Because all customers in an interconnected region are interdependent, a shortage of resources for some customers in the region can lead to a shortage for the entire region, which threatens reliable grid operations and risks sustained shortages with attendant high prices for the region.

459. We propose a resource adequacy requirement to provide for sufficient supply and demand resources to avert such shortages. Under these procedures, we believe that involuntary curtailment will rarely if ever be employed. However, consistent with current policies, the proposal must include procedures for such emergency conditions.

1. The Reason for the Requirement

460. The Commission proposes to adopt a resource adequacy requirement to help ensure development of the infrastructure needed for reliable transmission system operation. Because electricity cannot be generated and easily stored for future delivery, extra generating and demand response resources are needed to serve a function similar to storage in the natural gas industry; other commodity markets would call these a supply inventory. The cost of necessary reserves is analogous to the necessary cost of storage or inventory.

461. A requirement to assure adequate long-term resources is currently needed because spot market prices do not consistently signal the need for new infrastructure in the electric power industry. Most resources take years to develop and spot market prices alone may not signal the need to begin development of new resources in time to avert a shortage. Moreover, spot market prices that are subject to mitigation measures may not produce an adequate level of infrastructure investment even after a shortage occurs. Further, as long as regional resources are made available to all regional load-serving entities and their customers during a shortage, such entities have the incentive to lower their supply costs by depending on the resource development investments of others, a strategy that leads to systematic under-investment in infrastructure by all load-serving entities in the region.[217]

a. Spot Market Prices Alone Will Not Signal the Need To Begin Development of New Resources in Time to Avert a Shortage

462. The spot market price does not yet work well to produce long-term reliability investment, even without price mitigation, for several reasons. Extra resources need to be planned in advance for electricity because, when prices rise, demand is not reduced quickly and new generation cannot be added quickly. Both the demand for electricity and the supply of new generating capacity generally respond very slowly to price.

463. Regarding demand response, most retail customers buy power at a regulated fixed price. Even in states that have approved retail competition, customers are often shielded for years from price changes by a rate freeze. They are unaware of hourly changes in the cost of producing electricity. Electric meters are read monthly, and customers see only the imperfect price signal of a monthly bill rendered after electricity is used. Although larger commercial and industrial customers can be more price responsive, for many of them electricity is a small fraction of their cost of doing business and may receive little managerial attention. It takes time to develop the administrative rules and the technical capability to reduce consumption. As a result, most demand today is unable to respond to real-time prices because of insufficient price information, inflexible rate designs, and metering limitations.

464. The response of new generating capacity to price is slow because it takes time to plan, site and construct new electric power generating facilities. Development of a new power plant takes two to five years or more, depending on the type of plant and its location. It can take even longer to site the transmission lines needed to transmit the power to customers.

465. These factors together can lead to sustained periods of inadequate supplies, threatening the reliable operation of the bulk power system. Insufficient demand response to price and the slow supply response to price can combine to produce electricity shortages that not only threaten reliability but also can raise day-ahead and real-time market prices significantly.

466. Further, rushing to relieve inadequate regional supplies and reduce high regional spot prices may bias construction choices toward supply resources that can be constructed quickly, perhaps sacrificing long-term cost minimization, environmental concerns and fuel diversity goals. Most customers prefer spreading out resource capital costs over time to concentrating them into a peak period. A resource adequacy requirement accomplishes this.

b. Spot Market Prices That Are Subject to Mitigation Measures May Not Produce an Adequate Level of Investment When a Shortage Occurs

467. Customers object strongly to inadequate supplies—and high prices when supplies are inadequate—because electricity is essential for many uses and customers cannot turn to substitutes to reduce electricity demand. Electric power drives modern life, and there is significant societal disruption from even short supply interruptions.

468. For these reasons, customers want protection from the exercise of market power that may occur when supplies are short, and some form of market power mitigation is needed under these circumstances, as discussed in the market power mitigation section. However, market power mitigation may tend to suppress the scarcity price that

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[217] For further discussion of these topics, *see e.g.,* Steven Stoft, *Power System Economics* (IEEE Press, Wiley-Interscience, 2002) especially ''Fallacy: The 'Market' Will Provide Adequate Reliability.''

would otherwise stimulate new resource development. As a result, investors may not develop adequate infrastructure—making the problem worse—unless there is a provision for resource adequacy. Such a provision helps customers by assuring adequate supplies and helps generation developers by creating a demand for resources in advance of electricity prices doing so alone.

c. Load-serving Entities Will Underinvest in Resources Needed for Reliability if They Can Depend on the Resource Development Investments of Others

469. In an interconnected region, the failure of some market participants to secure sufficient long-term electricity resources can contribute to a shortage that affects reliability and spot market prices for all participants in the wholesale power market.

470. Under retail competition, load-serving entities competing for customers may compete on the basis of cutting the cost of forward contracting for resources unless they all are held to the same resource adequacy requirement. Without such a uniform requirement, those suppliers that contract for reserves may lose market share, and those who do not may gain a market share—at least for a short period of time. For this reason, a load-serving entity has an incentive to minimize its own costs by procuring few or no reserves and relying on others to develop reserves. If the rules allow it, some load-serving entities will try to have the reliability benefit of adequate regional resources that other load-serving entities pay for or that uncontracted-for generation must offer pursuant to market power mitigation.

471. Severe power shortages lead to public insistence on government intervention. Both historical practice and recent events indicate that during a shortage those load-serving entities that have reserves are required by government to share them with those that do not have reserves. There are at times state regulatory and gubernatorial requirements to protect customers from blackouts or high prices, a U.S. Department of Energy requirement for utilities to share power reserves in an emergency, or a Commission requirement to bid all available power into an organized spot market.

472. Some market participants depend on government intervention during severe shortages as an alternative to paying their share of the cost of developing adequate regional resources. As long as regional reserves are made available to all, a load-serving entity can reduce its own reserve resource costs and rely on the resources of others. The result is that all load-serving entities will tend to follow this strategy, leading to a systematic underinvestment in resources needed for reliability.[218] The current physical configuration of the transmission grid often exacerbates this problem because it is often difficult to impose the results of one party's resource shortfall solely on that party. For example, if several competing load-serving entities serve customers in the same electrical neighborhood, it may not be technically feasible to curtail some of these customers and not others during a shortage.

473. These arguments persuade us to propose a long-term resource adequacy requirement in the Standard Market Design rule. A resource adequacy requirement provides for timely development of supply and demand response resources to assure regional resource adequacy. It helps smooths out the price swings of the electricity business cycle. A well-designed resource adequacy requirement supports competitive markets if it allows suppliers to compete to provide infrastructure and buyers to choose the infrastructure with the best combination of features such as cost, reliability, environmental effects, and service life.

2. Basic Features of the Requirement

474. We propose to require, as set out in the proposed regulations, that an Independent Transmission Provider must forecast the future demand for its area, facilitate determination of an adequate level of future regional resources by a Regional State Advisory Committee, and assign each load-serving entity in its area a share of the needed future resources based on the ratio of its load to the regional load.

475. The Independent Transmission Provider must assure that each load-serving entity in its area acts to meet its share of the future regional needs—through self-supply, contracts to purchase generation, biddable demand or other demand response program. The Independent Transmission Provider must apply standards, discussed below, to audit the adequacy of the plans of load-serving entities to meet the future resource needs of its area. Moreover, the Independent Transmission Provider must check that resources are not double-counted by different load-serving entities. In a region with more than one Independent Transmission Provider, each Independent Transmission Provider must coordinate this checking responsibility with all the Independent Transmission Providers in the region.

476. If a power shortage occurs during which the Independent Transmission Provider is unable to satisfy demand in the spot market and also meet its reliability requirement for a minimum level of operating reserves, the Independent Transmission Provider must add a per-megawatt-hour penalty during the shortage to the price of energy taken from the spot market by a load-serving entity that did not meet its share of the regional needs for that year.

477. Further, if the operating reserve level decreases to the point that the Independent Transmission Provider must curtail load, the Independent Transmission Provider must, to the extent possible, curtail the spot energy purchases of the load-serving entity that did not meet its resource adequacy requirement before curtailing the spot energy purchases of load-serving entities that did. The load-serving entity is subject to such first curtailment during a shortage only in the amount by which it falls short of meeting its share of the resource adequacy requirement for the year in which the shortage occurs.[219]

478. If a shortage remains after all such first curtailments are completed and additional curtailment is necessary, the remaining loads of the first-curtailed load-serving entities and the loads of other load-serving entities that have satisfied their resource adequacy requirement would be curtailed under the same protocol. In this case the shortage may be attributable to certain load-serving entities of either type that, whether or not they may have met their resource adequacy requirement. We expect that those load-serving entities that are short of their own reserves would lose service ahead of those that are not short.

479. The approach to resource adequacy proposed here is intended to assure the development of both new supply and demand response resources.

[218] This is the well-known "free rider" problem for public goods, those for which consumption cannot be limited to those who paid for them (such as parks and national defense) and that are available to all users even if only some users pay for them. *See, e.g.,* Lee S. Friedman, *The Microeconomic of Public Policy Analysis,* Princeton University Press (Princeton, NJ 2002), which states at pages 597–598:

> If their provision were left to the marketplace, public goods would be underallocated. The reason is that individuals would have incentives to understate their own preferences in order to avoid paying and free-ride on the demands of others. Thus, public goods provide one of the strongest arguments for government intervention in the marketplace: not only does the market fail, but it can fail miserably.

[219] A load-serving entity that continues to take spot market energy despite the curtailment order of the Independent Transmission Provider would be subject to a very high penalty under the tariff.

This approach focuses on encouraging payment to fund construction of future resources instead of avoiding payment of a penalty for inadequate current resources as in some current programs. The forward-looking planning horizon provides time for market entry by new suppliers, which will help to check any market power among existing suppliers.[220]

480. This proposal is designed to complement, not replace, existing state resource adequacy programs. A vertically integrated utility satisfying a current state resource requirement that equals or exceeds its share of the resource adequacy requirement would not have to do anything more. For those states that have retail choice programs in which retail customers or their suppliers buy power from a multistate region, we intend this approach to provide for regional adequacy in a way that no one state alone may be able to accomplish.

481. The proposed approach is like the traditional reserve margin requirement imposed by states on monopoly utilities. It worked well during most of the last century to ensure adequate supplies, and is still in use in most states, especially states that have no retail choice program. However, because the traditional approach relies on individual utility plans and resources, it might not continue to work well in a region where utilities now rely on independent power producers in several states for new resources instead of their own new generation. The traditional reserve margin requirement may also not work well in a region where some states have traditional monopoly utilities and others have retail choice because a shortages in one state can affect all states in the region.

482. To continue to rely on the traditional reserve margin requirement, it has to be adapted to have a regional focus and to fit with competitive procurement. We propose a resource adequacy requirement of this type.

483. The resource adequacy requirement proposed here is unlike that of the three Northeast ISOs. ISO-New England, the New York ISO and PJM each impose an obligation on load-serving entities known as an Installed Capacity (ICAP) requirement. The three requirements differ, but share some basic characteristics. We are reluctant to impose a national ICAP requirement, in part because of our concern about the effectiveness of the existing ICAP programs and in part because they were based on former voluntary tight power pools. The three ISOs play a strong role in administering the program, a role that may not suit regions without a history of tightly coordinated reserve sharing.

484. The basic features of the proposed requirement are set out next, including discussion of the demand forecast, the level of resource adequacy, the role of the load-serving entity, the load-serving entity's share of the regional resource adequacy requirement, the types of resources that can satisfy the resource requirement, the standards that each type of resource must meet, the planning horizon, enforcement of the requirement, and regional flexibility.

a. Demand Forecast

485. An Independent Transmission Provider would be required to do an annual demand forecast for its area. The forecast would look ahead for the time period needed to add new supply and demand response resources. We will refer to this time period as the planning horizon, a topic discussed further below.

486. Demand forecasts have long been used in the utility industry to determine the need for future resources and to plan new infrastructure investments. The Independent Transmission Provider may undertake a ''bottom up'' method of demand forecasting by adding up the demand forecasts of its component areas where they can be relied on.[221] This may be accomplished through a collaborative process with all stakeholders.

b. Level of Resource Adequacy

487. After the area's demand is forecast, the Independent Transmission Provider must assess whether the collective resource plans of load-serving entities in this area are adequate to meet the projected future peak need with allowance for adequate reserves. In today's more competitive environment, the effectiveness of single-utility supply forecasts may be reduced. Under open wholesale transmission access, regional patterns of energy flow can change quickly, making single-utility transmission planning difficult. Generators sited in a utility's service territory, if not under contract, may export power to another area or region. Single-utility forecasting is also more difficult today because power market information is considered very sensitive. Competitive suppliers are reluctant to share this information with a utility that is a potential competitor. A regional assessment of regional supply adequacy by one or more independent entities in the region would help overcome these difficulties.

488. Further, close coordination is needed between those planning generation and transmission because the location of planned generation affects the location of planned transmission and vice versa, and an Independent Transmission Provider (or a group of Independent Transmission Providers acting collectively in a region with more than one Independent Transmission Provider) is in the best position to coordinate these planning functions.

489. Once the future level of supply and demand resources is determined, the region must assess whether this level is adequate. This requires a regional determination of the appropriate level of resource reserves, for example, whether the reserve margin (if reserve margin is the region's measure of resource adequacy) should be 12, 15, 18 percent, or another level. We seek comment on and encourage regional discussion of appropriate planning targets in energy-limited areas, specifically on how to incorporate volatility of annual hydropower supply.

490. Each region should take its own characteristics into account when determining the appropriate level, subject to a minimum level of resource adequacy for all regions discussed below. This determination has been made by load-serving entities under the oversight of the states, and we want this state oversight to continue. We propose that the level should be set by a Regional State Advisory Committee.[222] States in the region should have this strong role in determining the level of resource adequacy because a higher level provides greater reliability and also incurs higher costs that affect most retail customers. State representatives are in the best position to determine on behalf of retail customers the trade-off between the cost to the customers of extra generation and demand response reserves and the difficult-to-quantify benefits to the customers of increased reliability and reduced exposure of the region to the effects of a power shortage.

491. We will require the Independent Transmission Provider (or the several

[220] A regional resource adequacy requirement should also provide substantial evidence of need for infrastructure to investors as well as to siting authorities. This should aid suppliers in acquiring financing and should facilitate siting decisions. An added benefit may be the ability to better predict, plan, and finance new transmission system facilities associated with these resource requirements.

[221] A load-serving entity has an incentive to underestimate its future load if doing so would reduce its share of the resource adequacy requirement. For an analysis of bias in demand forecasts, see Mark Bock, ''Analysts hunt for bias in NERC forecasts,'' *Electric Light & Power*, July 2002.

[222] *See* the following section, State Participation in RTO Operations, for a discussion of the composition of the advisory committee.

Independent Transmission Providers in a region with more than one such Provider) to provide a forum and assistance to the Regional State Advisory Committee to establish the appropriate level of resource adequacy for the region. Because many Independent Transmission Providers encompass more than one state (or province), the Independent Transmission Provider's role as a facilitator will be helpful in establishing the regional reserve level.

492. However, we ask for comment on what fallback provision should be employed if the Regional State Advisory Committee does not reach agreement on the appropriate level of resource adequacy. We believe that having different reserve levels in different states in the same region maintains the problem of some customers relying on the reserves of others.

493. We are concerned that the requirement be set so that the Independent Transmission Provider can operate the interstate transmission system reliably with real-time operational resource adequacy. We are also concerned that inadequate resources could lead to poor market liquidity and even shortages with sustained high wholesale power prices. For these reasons, we propose to adopt a 12 percent reserve margin [223] as a minimum regional reserve margin for all regions with the understanding that this is low by traditional generation adequacy standards and that the Regional State Advisory Committee in each region may set this number higher for the region to achieve greater reliability. We selected a 12 percent reserve margin as a minimum in that it is two-thirds of the typical historical reserve margin target of 18 percent for large utilities.[224] We emphasize that most utilities historically used a reserve margin well above 12 percent. This 12 percent reserve margin is intended to be a safety-net level in planning for reliable future transmission and market operations and not to be the target reserve level for the region that should be established by the Regional State Advisory Committee.

[223] The reserve for a period is the amount of resources expected to be available during the period less the forecast peak load during the period. The reserve margin is the ratio of the reserves to the forecast peak load during the period, expressed as a percentage. A region may use another measure of adequacy as long as the minimum level is the arithmetic equivalent of a 12 percent reserve margin. For example, many use capacity margin, which is the ratio of the reserves to the amount of resources expected to be available during the period, expressed as a percentage. A capacity margin of 10.7 percent is the same as a reserve margin of 12 percent. Some may measure adequacy with a loss-of-load probability, called LOLP, which is a statistical measure of the expected total time during a period that generation will be unable to meet load. The common U.S. standard is one day in ten years, which means that the sum of the hours (or fractions of hours) during a ten-year period when generation is expected to be short is 24 hours. Reserve margin cannot be translated directly into LOLP without studying a particular system. For example, an area served by a few large generators is more vulnerable to a shortage caused by an outage of one or two large generators than a similar area served by many smaller generators. The area with a few large generators may need a larger reserve margin to achieve the same LOLP. A general rule-of-thumb for a large U.S. utility system is that an LOLP of one-day-in-ten-years is achieved with a reserve margin of about 18 percent.

c. Load-serving Entities

494. Each load-serving entity must satisfy a portion of the regional resource adequacy requirement. Load-serving entity here means any entity that uses transmission in interstate commerce to provide power to load, whether a traditional distribution utility or an energy service supplier that aggregates retail loads under a retail access program.

495. A large retail industrial or commercial customer that has retail access rights and buys power directly from suppliers is also considered a load-serving entity. If it does not buy power from another load-serving entity but uses the interstate grid to buy power directly from a supplier, it too would be required to meet its share of the resource adequacy requirement. As for other load-serving entities, their reserves may include the ability to reduce their own demand on the grid.

496. A load-serving entity may choose a higher level of reliability by developing more supply or demand response resources than required. Further, a load-serving entity may choose greater reliability and price assurance by procuring additional reserves for its own use. In particular, customers in a load pocket that is served by a few large generating units may need a higher reserve margin to have the same level of reliability as customers outside a load pocket.

d. Load-Serving Entity's Share of the Regional Resource Requirement

497. Once the future regional requirement is determined, each load-serving entity's share of the regional requirement must be determined. Meeting a regional resource adequacy level does not assure that every part of the region has adequate resources if there are internal transmission constraints or if resources are counted that may be sold outside the region, retired before needed, or otherwise made unavailable. For these reasons, it is important that resources not be considered merely regional but be associated with and committed to particular load-serving entities.

[224] The target level of these reserves, often called planning reserves, is not the same as the operating reserve level, a subject treated further below.

498. We request comment on two methods for determining each load-serving entity's share of the regional requirement. One is to allocate the future resource adequacy needs to loads based on each load's forecasted future demand. For example, if the load forecast is for three years ahead and a particular load is growing faster than the regional average, its share of the adequacy requirement could be based on its forecast load ratio share for three years ahead, not on the present load ratio share. This method assigns more adequacy responsibility—and cost—to faster growing loads. However, if the Independent Transmission Provider's forecast is made through a ''bottom up'' method that adds up individual load forecasts, it must rely on each load to report its growth rate accurately. This approach creates an incentive for loads to understate their growth to lower their resource costs.

499. The other method is to allocate the future adequacy requirement to loads based on each load's most recently documented load ratio share. This method is less subject to manipulation. However, an area with a slow load growth located within a region of generally high load growth may subsidize the high reserve needs of its neighbors.

500. We ask for comment on which of these two methods the Commission should choose in the Final Rule. Alternatively, we ask whether this issue should be left to regional determination.

501. Once each load-serving entity's share of the regional adequacy requirement is determined, the Independent Transmission Provider must inform each load-serving entity of its share. It must require each load-serving entity to report and document how it plans to meet its adequacy requirement.

502. The time available to the load-serving entity from being informed of its resource share to having to report to the Independent Transmission Provider must be adequate to allow it to develop arrangements for meeting future resource needs. We ask for comment on how much time is needed for these purposes.

e. Resources That Can Satisfy the Resource Needs

503. Each region's resource adequacy requirement could be satisfied by a combination of generation,

transmission, and demand response infrastructure.

(1) Generation and Transmission

504. The supply requirement could be satisfied by self-owned generation, local distributed generation, or firm bilateral contracts for power that are backed by specific generating units (or a portfolio of designated generation units). The firm bilateral contract could be either a forward contract for the purchase of power or an option to purchase energy under specified shortage or price conditions, as long as the firm contract is backed by specified generating units.

505. In any of these cases, the generator must be committed to supply power to the load-serving entity, at least under certain conditions. Self-owned generation that is committed to another load-serving entity, unless it can be recalled during a shortage, would contribute to the other load-serving entity's requirement, not the requirement of the load-serving entity that owns it. Generation under contract must specify that the generator will be available to the load-serving entity—or at least to the market that the load-serving entity participates in—under conditions set out in the contract. These conditions, discussed further below under generation standards, must be adequate to meet the region's need for reserve resources.

506. The firm contract would be for a forward-looking period that would at least cover the planning horizon, which (as discussed further below) would be selected regionally and should be based on the time needed to develop new resources in the region. The load-serving entities must also demonstrate that future use of the designated resources is physically feasible and, in particular, that transmission is or will be available to deliver energy from a generator to the load-serving entity that claims it in its resource plan.

(2) Demand Response

507. Allowing demand response infrastructure to satisfy the requirement removes bias toward exclusive reliance on new generation to meet regional needs. Better demand response to high prices when a shortage condition approaches will lower demand and reduce the use of high-cost power resources. Demand response will help ensure reliability, prevent a shortage that could produce a curtailment, act as a check against market power, and provide a yardstick for the value that buyers place on supply.

508. Biddable and interruptible load can satisfy the resource adequacy requirement as well as generation.[225] A load-serving entity that does not want to pay for generating reserves can substitute a demand response alternative to meet its resource adequacy requirement. Under some state programs, the larger retail customer may be rewarded for reducing its electric use in addition to enjoying a reduced bill for reduced consumption. Several states have this type of biddable load reduction; it is one way to allow the customer to determine how much it is willing to pay for power. Further, competitive energy service suppliers can compete for load by offering lower rates to customers who agree to participate in demand response programs such as remote air conditioner cycling, aggregate building load management, and other proven demand response and load management options.

3. Resource Standards

509. The Independent Transmission Provider must determine if each load-serving entity's planned resources meet certain standards. The resources must meet the standards to count toward satisfying the entity's share of the regional resource requirement. Both generation and interruptible or biddable load must meet standards to satisfy the requirement.

510. We propose here certain minimum standards for comment. We also are considering in the Final Rule to ask the North American Energy Standards Board (NAESB) to develop more detailed standards for determining whether resources satisfy the resource adequacy requirement, and we seek comments on this approach.

a. Generation Standards

511. Generation must be owned by or under contract to the load-serving entity and committed to meet the resource needs of the load-serving entity at least during certain conditions such as an operating reserve shortage. The Independent Transmission Provider must be satisfied that the generation is physically feasible; that is, the generating units are capable of generating the power planned, and enough transmission is available to deliver the power from the generating station to the particular load. The generating units under contract must be real and specific generators. This is so that only real generation that can avert a supply shortage is counted and so that its transmission over the grid can be assured. For example, it does no good for a load on Long Island to claim a generator in western New York as a resource if the power cannot be delivered to Long Island during a Long Island shortage.

512. Because the purpose of this requirement is to encourage the development of new resources including new generation, generation under contract for development within the planning horizon should satisfy the requirement. Should the Commission specify the contract content needed to rely on generation under development? If so, should we refer this matter to NAESB to determine the content?

513. For these reasons also, a contract with a marketer to deliver power at a future time from unspecified sources cannot satisfy the requirement. The purpose here is not to transfer financial risk for nonperformance to a marketer but to ensure performance, that is, to ensure that enough actual, deliverable generating capacity is available or developed at satisfactory locations to avert a future shortage. However, a forward contract with a marketer that is linked to specific generation and demonstrates transmission adequacy would satisfy the requirement. We ask for comment on whether we should allow a liquidated damages contract for power from unspecified sources to be included in the resource adequacy plan, and also on whether we should allow a load-serving entity that initially fails to satisfy the resource adequacy contract, but later brings in new resources under a liquidated damages contract for the amount of its resource deficiency, to avoid the penalty price and first curtailment in the spot market during a shortage.

b. Transmission Standards

514. Generation must be deliverable to satisfy the requirement. A Congestion Revenue Right for the appropriate year is one way to satisfy this requirement. We propose to adopt a practice (used in PJM) that allows a resource owner to pay for the development of adequate transmission to deliver its energy to a load and then to sell its Congestion Revenue Rights while still satisfying the requirement that its generation be deliverable. Should a commitment by any load-serving entity to pay congestion costs no matter how high also satisfy the requirement? If so, how should the Independent Transmission Provider respond if the sum total of all such commitments exceeds the available capacity of a bottleneck interface?

515. A robust transmission system with few constraints may allow a load to rely on generation and demand

[225] The traditional reliability reserve margin allows interruptible load to be counted equally with generation resources, with some exceptions.

response reserves that are farther away than if the transmission system is weak. Supply reserves that are not deliverable to the load claiming them when needed cannot be counted as satisfying that load's reserve requirement.

516. For transmission as well as for generation and demand response, the purpose of this requirement is to encourage the development of least-cost resources, which may include new transmission needed to access existing or new generation. We believe therefore that planned transmission with full siting approval and completion expected within the planning horizon should satisfy the adequacy requirement.

c. Demand Response Standards

517. Demand response must also be verifiable to satisfy the adequacy requirement. The Independent Transmission Provider must have confidence that the demand response resource will be able to contribute when called on during a shortage. Demand response may be obtained through biddable demand reduction, interruptible load, or other dependable load management program. Distributed generation that is interconnected with a customer, a load-serving entity, or an energy services company, although it is technically generation and not demand response, can also be used by a local distributor to reduce the demand that the distribution system places on the grid. With biddable demand reduction, certain loads will be assured of dropping off the system at known price levels; the amount of load dropped should increase with the price.

518. With interruptible load, a customer pays a lower power price year round but will be interrupted under defined shortage conditions; the load is subject to a simple on-off criterion. An important feature of this proposal is that the load-serving entity plan that depends on interruptible load to meet its resource adequacy requirement must be capable of being implemented. The Independent Transmission Provider may require, for example, that the load-serving entity install equipment that gives it direct control over the loads of the customers that are subject to the interruption. We recognize, however, that installation of such equipment may be too costly or otherwise impractical in some situations. In that case, the load-serving entity must have a satisfactory arrangement for implementing its interruptible load program under the instructions of the Independent Transmission Provider.

519. If load in an area ''buys'' demand reduction from another area (in effect buying some of that other area's freed-up generation), the transmission needed to deliver the freed-up generation to the load that relies on it must be available.

4. Planning Horizon

520. The purpose of a forward-looking resource adequacy requirement is to create a demand for new resource entry in advance of a shortage so that enough supply construction and demand response infrastructure installation are begun in time to avert the shortage. The planning horizon for each region is the number of years ahead for which the Independent Transmission Provider must forecast annually its area's load, as well as the number of years ahead for which load-serving entities must show that they have adequate resources. For example, the Independent Transmission Provider could forecast its area's peak load three years from the present and require that each load-serving entity in its area have acceptable plans today to have enough resources three years from now to meet the forecast peak with a reserve margin of 12 percent. In this example, the planning horizon is three years and the reserve level is the minimum 12 percent.

521. The choice of the planning horizon affects the lead time for construction and the duration of forward contracts that can satisfy a resource adequacy requirement.[226] The traditional state-required electric company planning horizon was 10 to 20 years. The horizons were established when the industry relied on new large hydroelectric, coal, or nuclear facilities to meet growing load, and these facilities could take 10 or more years to site and construct. Today, most new resources are planned and developed over a much shorter time frame, in part because of the reliance on low cost natural gas. However, this planning horizon could change again if natural gas were no longer the main fuel of choice.

522. Because the planning horizon should be no less than the time frame for developing new resources and development times vary from region to region, the planning horizon can depend on that region's reliance on coal, gas, wind, hydropower or new demand-response technology for new supply. This argues for allowing each region to determine its own appropriate planning horizon.

[226] For example, forward-contracting for supply with one-year contracts that begin today and end after one year would not satisfy an adequacy requirement with a three-year planning horizon. A one-year contract for the third year forward would satisfy the goal for that year.

523. We propose to make the planning horizon a matter for regional choice. Regions should consider several factors in selecting the planning horizon. Most important, the planning horizon chosen should not be so short that it fails to motivate and achieve construction of generation and demand response resources in time to avert a shortage. Greater fuel diversity may be achieved with a longer planning horizon. If the horizon is short, two years for example, load-serving entities may have an incentive to select resources that can be developed in two years or less, such as peaking units and some other gas-fired generators. A longer planning horizon allows time for development of other resources such as coal-fired generation, hydroelectric resources, and some advanced demand response programs. Load-serving entities in retail choice states would benefit from a shorter planning horizon because it would reduce their business risk associated with demand forecast error. Also, they may not want to enter into bilateral contracts for supplies for a time period that is longer than the duration of their contracts with their customers.

524. We propose to have the Regional State Advisory Committee determine the planning horizon for the region. The Independent Transmission Provider (including each Independent Transmission Provider in a region with more than one Independent Transmission Provider) must provide information and support to the Committee, as requested, to help it to determine the region's planning horizon. We request comment on how to resolve any lack of consensus within the Committee regarding the appropriate planning horizon. We also ask for comment on whether the Commission should establish limits on the region's choice of planning horizon, such as at least three years and no more than five years.

525. We also ask for comment on whether to have a resource adequacy requirement before the end of the first planning horizon period. For example, if the horizon is three years, should there be a requirement for resource adequacy in the first two years?

5. Enforcement

526. Here we explain in more detail our proposal to enforce the resource adequacy requirement, along with some alternative enforcement procedures, and ask for comment on the most effective enforcement method.

527. Unlike some ICAP requirements, the approach adopted here does not require a load-serving entity to pay a penalty in the near term for failure to

have adequate future resources. Our proposed approach relies primarily on two enforcement mechanisms: (1) a Commission-set tariff penalty imposed on a load-serving entity that threatens reliable transmission operation by taking energy from the spot market during a shortage in a year for which it fails to meet its resource adequacy requirement, and (2) a Commission requirement that the spot market electric service of such a load-serving entity must be curtailed first when the shortage that is severe enough to require that some customers be curtailed. Each of these mechanisms, the penalty rate and the load curtailment, would occur at the end of the planning horizon, not the beginning.[227]

528. The first mechanism applies during a power shortage in which the Independent Transmission Provider is unable to satisfy demand in the spot market and also meet its reliability requirement for a minimum level of operating reserves.[228] As a shortage develops, price is expected to increase in the spot energy market. A load-serving entity that is short on self-generation, bilateral contracts (including affiliate generation and call contracts), and demand response resources will be dependent on the spot markets to meet its resource needs. The rising price in the spot market is, of course, a principal incentive for the load-serving entity to develop adequate supply and demand resources. If shortage conditions develop to the point where the Independent Transmission Provider cannot serve all load and maintain the minimum level of operating reserves, it must take some action to maintain reliable operation. Some load must be given either an economic incentive to exit the spot market or an order to stop taking power from the spot market. We propose that these measures be applied first to the load of the load-serving entities that did not meet their share of the resource adequacy requirement. However, the load-serving entity is subject to a penalty and first curtailment during a shortage only for spot energy purchases [229] and only in the amount by which it falls short of meeting its resource adequacy requirement.

529. Specifically, we propose that during such a shortage the Independent Transmission Provider must add a per-megawatt-hour penalty price to the price of energy taken from the spot market by a load-serving entity that did not meet its share of the regional needs for that year. This rate would apply only to spot energy purchases, not to power received from the load-serving entity's self-generation or bilaterally contracted energy. However, it would apply to spot market energy sales needed to correct for imbalances associated with energy from these sources. We would set the penalty price high enough that we do not suggest that failing to meet a resource adequacy requirement and paying a penalty rate is an acceptable alternative to developing new resources, which would be the case if the paying the penalty appears to be less costly over time.

530. The penalty price would increase in stages as the shortage becomes more severe. For example, the penalty price could be $500 (in addition to the spot market energy price) when operating reserves are just below the minimum level, $600 when operating reserves are more than below 1 percent below the minimum level, $700 when operating reserves are more than 2 percent below the minimum level, and so on. We ask for comment on having such a graduated penalty and the appropriate penalty rates.

531. This first enforcement mechanism provides a price-based mechanism to enforce a resource adequacy requirement and to restore the transmission system to a reliable condition. Most system operators—and their regulators—treat load curtailment (voltage reductions and blackouts) as a last resort measure, and operators may violate the reliability rule for minimum operating reserves rather than implement a load curtailment to satisfy the minimum operating reserve criterion.[230] We believe that the penalty price should be set high enough to bring about voluntary load reduction by a load-serving entity and thus restore the system to a reliable condition.

532. The second enforcement mechanism is applied when the operating reserve level decreases to the point that some load must be curtailed.[231] The spot energy purchases of that load-serving entity load would be reduced by the amount of its resource deficiency and consequently some of its customers would be curtailed before the loads of other load-serving entities.[232]

533. In support of this second mechanism, we will require the Independent Transmission Provider to

[227] For example, if the planning horizon is three years, a demand forecast would be made in 2004 for the year 2007. The Independent Transmission Provider would assess the adequacy of resources for 2007 and allocate the resource adequacy requirement for 2007 among the load serving entities. The entities would submit to the Independent Transmission Provider in 2004 their plans to meet their share of the 2007 resource adequacy requirement. An entity fails to submit in 2004 a satisfactory resource plan for 2007 would not be subject to the penalty rate or be among the first curtailed during a shortage in 2004 but would be subject to the penalty rate and be among the first curtailed during a shortage in 2007. Next year, in 2005, the same process repeats: the Independent Transmission Provider would forecast demand in 2008, and so on.

[228] Operating reserves are generation and demand response resources needed to keep the system in balance, follow changes in load, and make up for a ''contingency'' such as the loss of the largest generating unit or of a major transmission line that delivers more power than any one generating unit. The North American Electric Reliability Council and the regional reliability councils set rules regarding the minimum operating reserves that must be maintained by the system operator for reliable operation. The rules are expressed in a formula so that the value of the minimum operating reserves changes during the day with load conditions and with the sources of supply. Typically, for a large utility, the minimum operating reserves are in the range of 5 to 8 percent of load, but this can vary significant with changing conditions. An operator that operates with less than minimum operating reserves threatens not only its own reliable operation but the reliability of its electrical neighbors.

[229] These actions apply to spot energy purchases onluy. In the event that the load-serving entity that failed to meet its share of the resource adequacy requirement has adequate supply and demand resources outside the spot market available to it at the time of the shortage, the Independent Transmission Provider would continue to provide transmission to support delivery of these resources. This proposal gives deference to the ownership and contractual right to use self-generation, bilateral contracts, and demend response resources, and it encourages the development of such resources during the planning horizon period by those entities that failed to plan adequately at the beginning. It also discourages contracting with unreliable resources to meet the resource adequacy requirement because each load-serving entity must actually rely on its resources to meet its resource needs.

[230] We will not overturn this practice by requiring curtailment of load immediately to restore the minimum operating reserve level. Some regions have a regional policy of taking action to reduce voltage or shed load only when operating reserves fall to some fraction, such as three-fourths or three-fifths, of the minimum operating reserve requirements of the reliability organizations.

[231] Regional practice will determine when load must be curtailed to maintain reliable operation. Operators may continue to follow their existing reliability practices: those that do not curtail service immediately when the operating reserve level goes below the minimum must impose the penalty price on resource-deficient load-serving entities. However, it is not our intent to require an operator to violate a reliability rule by providing service with a penalty price instead of enforcing its reliability rule through load curtailment. We believe that a high penalty price may result in the needed load reduction. Whenever the operator must curtail load to maintain reliability, it should do so. Our requirement goes to which load must be curtailed first when curtailment of load is necessary, not to when curtailment becomes necessary.

[232] An individual load-serving entity may run short of planned-for resources when its region is not experiencing a regionwide shortage, for example, because of a combination of high demand on its own system and unplanned outages of its own resources. In this case it is not required to be curtailed because that load-serving entity may procure additional supplies from the short-term or long-term bilateral market or from the spot market. Since the region is not short, others are likely to sell power, including perhaps a portion of their reserves on the basis that the reserves can be recalled if a regionwide shortage occurs.

inform the load-serving entity's state regulatory authority [233] if the load-serving entity fails to submit a satisfactory plan for adequate future resources, thereby exposing its customers to possible penalties and future first curtailment during a shortage. Our intent is to rely on the traditional state role of enforcing a load-serving entity's reserve obligation. We believe that in most cases the state regulatory authority would prefer to have the load-serving entity meet the adequacy requirement as a condition of doing business in the state, rather than expose its retail customers to first curtailment. The state regulatory authority may wish to consider any decision of a load-serving entity not meet its resource adequacy requirement. It may want to ask the load-serving entity to identify which of its customers will be subject to first curtailment if the region is short of power.[234]

534. If the Independent Transmission Provider does not have direct control of the circuit equipment needed to implement a curtailment and relies on the load-serving entity to follow its instructions to implement a curtailment, the load-serving entity would be subject to a severe penalty for the unauthorized taking of power from the spot energy market because this jeopardizes grid reliability. We propose to charge the applicable Locational Marginal Price plus $1000/MWh for all unauthorized energy taken following an instruction to implement curtailment.[235] We also seek comment on whether the $1000/MWh penalty would be sufficient to deter unauthorized taking of energy and, if these penalties are paid, who should receive these revenues.

535. We believe that load-serving entities, under these enforcement provisions and under the oversight of state regulatory authorities, will meet their resource adequacy requirement and not be subject to these curtailment penalty and first curtailment provisions at all. If most meet the requirement as we expect, shortages and first curtailment of any that do not should occur infrequently.

536. Having presented our enforcement proposal, we suggest variations of this proposal and ask for comments on these alternatives. As mentioned, under our proposal the penalty rate or load curtailment would occur at the end of the planning horizon, not the beginning. However, we ask for comment on this approach compared to an alternative approach that may provide a more immediate and effective incentive to a load-serving entity to take action to provide for future resources well in advance of facing a penalty or first curtailment. This is to impose a penalty on the load-serving entity immediately (that is, in year 2004 to continue the example in an earlier footnote) if it fails to submit a satisfactory plan to meet its 2007 resource adequacy requirement. We did not propose this option as our first choice because it has some of the unfavorable features of some ICAP programs that focus more on avoiding immediate penalties than on motivating long term resource development. However, we ask for comments on the merits of this alternative approach.

537. As presented, the Independent Transmission Provider audits the plan of each load-serving entity only at the beginning of the planning period (in 2004 in the example above). We are concerned that a load-serving entity may submit a satisfactory plan but fail to fully implement the plan. The proposal permits but does not require the Independent Transmission Provider to audit each year the progress of the load-serving entity in implementing its plan, and we ask whether we should explicitly require this. If the load-serving entity's progress is unsatisfactory, should the Independent Transmission Provider find that it fails to satisfy its resource adequacy requirement? If the load-serving entity implements its plan but some of its resources fail to perform when needed during a shortage, should that load-serving entity, in addition to having a greater need for spot market energy at a presumably higher spot market price, also be subject to either of the enforcement mechanisms set out above?

538. Another feature of our proposal is that it would not affect electric service from the self-generation and bilateral contracts of a load-serving entity that fails to meet its resource adequacy requirement (except that it would be subject to a penalty price during a shortage for balancing energy in the spot energy market). We ask for comment on whether this proposal unduly weakens the incentive to develop regional resources and whether, in the alternative, the Independent Transmission Provider should first curtail service to the load serving entities that failed to meet their share of the resource adequacy requirement, including transmission service from resources acquired outside the spot market, freeing up those resources for the use of those that planned adequately.

539. Finally, our proposed enforcement mechanisms are designed to create an incentive to avoid a future penalty or first curtailment. During the public outreach process for developing this proposed rule, some commenters recommended a stronger Independent Transmission Provider role in compliance with a mandatory resource adequacy requirement. One proposal is for the Commission to require the Independent Transmission Provider to procure resources on behalf of load-serving entities that fail to meet fully their requirement and charge them for the cost of the resources.[236] Another is for us to require the Independent Transmission Provider to either (1) calculate an expected capacity deficiency and purchase the call options necessary to meet the adequacy requirement on behalf of the load-serving entities, allocating costs *pro rata*, or (2) require load-serving entities to purchase reserves at the price produced by an Independent Transmission Provider-run auction.[237]

540. These approaches have advantages as well as disadvantages. Among the advantages are that they provide a greater assurance of achieving adequate resources and avoid the possible pitfalls of applying penalty rates or first curtailment. Among the disadvantages are that they take away one demand response option, namely curtailment, from the range of policy choices. Also, the latter approaches appear to require the Independent Transmission Provider to take a position in the capacity market, which places the Independent Transmission Provider in a role that may be incompatible with its independence.[238]

541. What is the effect of these alternate enforcement mechanisms on the incentives and business risks of the

[233] In this section, the term ''state regulatory authority'' includes the retail rate regulating authority for load-serving entities not regulated by a state utility commission.

[234] Any necessary curtailment action, whether a first curtailment or any subsequent curtailment action may have to satisfy applicable state or local rules for ensuring that essential retail services (such as police, hospitals, fire stations) are maintained.

[235] *See* SMD Tariff, Appendix B, Section I.5.

[236] *See, e.g.*, Electricity Market Design and Structure, Docket No. RM01–12–000, comments of Reliant Resources, Inc., filed May 3, 2002, at pages 11–12, in Docket No. RM01–12–000.

[237] *See, e.g.*, Electricity Market Design and Structure, Docket No. RM01–12–000, comments of Mirant Americas, Inc. and Mirant Americas Energy Marketing, L.P. filed May 2, 2002.

[238] They also raises difficult jurisdictional questions, in that Commission has regulated the seller's side of wholesale transactions and the states have regulated the buyer's side. Under some of these proposals, we would have to distinguish a transmission penalty levied by the Independent Transmission Provider for a load-serving entity's failure to procure the resources needed to maintain transmission security from a Commission-enforced mandatory purchase of reserves by the load-serving entity.

load serving entities in the region? Is there another enforcement mechanism that is both appropriate and effective?

6. Regional Flexibility

542. We propose to apply the requirement set out above to all regions, including regions that already have an ICAP requirement that has been previously approved by the Commission. This requirement would replace the current ICAP program.

543. Some regulators, customers, and market participants have expressed dissatisfaction with the ICAP models presently in place. Some customers view ICAP as an added cost with no tangible benefits; they assert that the commodity being traded has little value because customers are paying for installed capacity but not receiving any greater assurance that generation adequacy is maintained. Some commenters say that, in some ICAP programs, a generator can receive an ICAP payment and later be released from the ICAP obligation for a relatively small penalty to sell its capacity in another market with a high wholesale price.

544. Existing local generators are said to have preferential ability to participate in the ICAP market. The ICAP payment goes to the existing generators and does not necessarily lead others to enter the market to increase capacity. Depending on how the ICAP rules are designed, existing generators may be able to exercise market power, forcing up ICAP prices. In some markets, trading has been so thin at times that there is a question about whether there is a competitive market price.

545. In some such cases, the ISO has intervened to set the price administratively, and market participants are concerned that the price does not reflect the forward value of generating capacity. Some contend that prices in the spot markets and bilateral markets, including long-term forward contract markets, appear to be not well correlated with ICAP market prices.

546. The generators object to ICAP price controls. Some power generators see short-term ICAP payments as providing inadequate assurance of capital cost recovery to motivate new investment. They prefer longer-term contracts to ensure that their investment costs will be recovered.

547. Finally, many parties object that ICAP focuses on power generation, ignoring the potential of demand response.

548. Although we propose that every region must adopt our approach, this approach offers significant regional flexibility. Our approach allows each region to set its own level of resource adequacy, set its own planning horizon, and select from a combination of supply and demand response resources for meeting its needs.

549. Our proposal permits but does not require a region to have its Independent Transmission Provider establish a market for acquiring and trading adequate resources. We believe that the bilateral market and other means can be adequate for acquiring and trading resources. Nevertheless, we ask for comment on whether, under the approach to resource adequacy proposed here, we should require an Independent Transmission Provider to create a market to facilitate load-serving entities meeting their resource adequacy requirement efficiently.

550. Despite the flexibility of our proposed approach, regions with a historical reliance on a tight pool for sharing reserve may argue for a continuation of some form of ICAP program. We ask for comment on how existing Commission-approved ICAP mechanisms can be transitioned and modified so as to be made consistent with our resource adequacy proposal here without disrupting financial commitments made under existing rules. What are the disadvantages of particular elements of the ICAP approach that should be avoided in the approach proposed here? Do any of the enforcement proposals or alternatives discussed above re-introduce any such disadvantageous elements?

K. State Participation in RTO Operations

551. States have an important role in the process of creating and sustaining an efficient competitive wholesale market for electricity. The Commission has already established state-federal RTO panels as a forum for the Commission and state commissioners to discuss issues related to RTO development. However, there currently is not a formal process for state representatives to engage in a similar dialogue with the independent entity that will operate the electric grid under Standard Market Design. Therefore, the Commission is proposing to establish a formal role for state representatives to participate on an ongoing basis in the decision-making process of these organizations.

552. We envision that the Independent Transmission Provider that operates the grid would have a Regional State Advisory Committee. The Regional State Advisory Committee should be formed and should have direct contact with the governing board, in a manner which recognizes its public interest responsibilities, and be designed to provide the board as well as market participants and the Commission with a consensus view from states in the area. The specifics of how this advisory committee would be formed and operate would be decided on a regional basis. This coordinated oversight will ensure fulfillment of federal public interest responsibilities in a manner that includes the views of states throughout the region. In this regard, we also encourage the participation of Canadian provincial authorities in this process.

553. We take note of the recent report by the National Governors' Association entitled ''Interstate Strategies for Transmission Planning,'' which recommends establishing ''Multi-State Entities'' to facilitate state coordination on transmission planning, certification, and siting at a regional level.[239] The report recognizes the critical role states currently play in siting as well as the need to address regional needs. The institution we propose here appears complementary to the National Governors Association's recommendation. In fact, it may be useful to have a single Regional State Advisory Committee rather than separate committees for siting and other issues. We seek comment on whether there should be a single Regional State Advisory Committee, or separate committees for siting and other issues. We also seek comment on how the state representatives should be selected (*e.g.*, whether the governor should select them or some other process should be used).

554. The Regional State Advisory Committee may work with the regional transmission organization to seek regional solutions to issues that may fall under federal, state, or shared jurisdiction, which may include but are not limited to:

a. Resource adequacy standards;
b. Transmission planning, expansion;
c. Rate design and revenue requirements;
d. Market power and market monitoring;
e. Demand response and load management;
f. Distributed generation and interconnection policies;
g. Energy efficiency and environmental issues;
h. RTO management and budget review.

Further duties may evolve with the development and operation of the regional councils.

555. As discussed, the Commission is proposing to require that the independent entity that operates the

[239] *Available in http://www.ng.org/center/divisions/1,1188,C__ISSUE__BRIEF^D__4110,00.html.*

markets under Standard Market Design will have a Market Monitoring Unit (MMU). The MMU will be required to report directly to the Commission and the independent governing board of the Independent Transmission Provider. The MMU should also provide its reports directly to the Regional State Advisory Committee. Finally, because of the regional nature of these organizations, there are many new issues involving rate design and revenue requirements. We believe that the Regional State Advisory Committees can bring a valuable regional perspective to these issues and should play a role in deciding these issues in partnership with the Commission. Once the advisory committees are established, we intend to work with them to establish protocols for deciding these regional rate issues. Additionally, the Independent Transmission Provider will be required to develop regional plans for transmission planning and expansion. We believe this is also an area where the Regional State Advisory Committee can bring a valuable regional perspective and should be consulted in developing these regional plans.

L. Governance for Independent Transmission Providers

556. The Commission has previously recognized the importance of independent governance of regional organizations in both Order No. 888 and Order No. 2000. In Order No. 888, the Commission required that ISO governance be structured in a fair and non-discriminatory manner and that the ISO be independent of any individual market participant or any one class of participants. The Commission also required that the ISO's rules of governance should prevent control, and appearance of control, of decision-making by any class of participants. Order No. 2000 built upon and extended this independence requirement to RTOs. In Order No. 2000, we reaffirmed our commitment to independence as a bedrock principle for regional organizations, and in this rulemaking we find that our commitment to independence also is critical to the successful implementation of Standard Market Design. Compliance with the independence requirement of Order No. 2000 is based on the independence of the Board of Directors and all employees of the RTO. The governance requirements for the Board of Directors is critical to ensuring that the RTO is independent and that the RTO's interests are aligned with the interests of the market as a whole rather than with particular market participants of classes or market participants. While we did not mandate detailed governance requirements for RTO boards in Order No. 2000, we stated that we would review on a case-by-case basis the RTO governance proposals and judge them against the overarching standard that the RTO's decisionmaking process must be independent of individual market participants and classes of market participants. We also required an audit of the independence of an ISO's governance process two years after its approval as an RTO.[240]

557. The Commission has considered on a case-by-case basis whether individual RTO proposals satisfy the Commission's requirements for independence.[241] We have required changes where they did not.[242] However, we are concerned that the lack of more definitive guidance from the Commission on governance may be hindering the development of larger RTOs. Also, we are concerned that the existing stakeholder process may not provide adequate representation for all market participants and interested parties. The lack of adequate representation may hinder development of alternative energy resources, such as distributed generation, renewable energy, or demand response programs, since these programs may be contrary to the business interests of certain market participants. Therefore, we are proposing to require that all Independent Transmission Providers satisfy specific governance requirements. Specifically, we are proposing to more clearly define the responsibilities of the Board of Directors, more clearly define the role of stakeholders in selection of the board and in the management of the Independent Transmission Provider, and to establish a process that would be used for selecting the Board of Directors by Independent Transmission Providers.

1. Responsibilities of the Board of Directors

558. As we have previously stated in both Order No. 888 and Order No. 2000, it is critical that the board be independent. The board's primary responsibility is to ensure that the markets operated by the Independent Transmission Provider are operated in a fair, efficient and non-discriminatory manner. The board's focus should be on the interests of the wholesale market, not the interests of particular market participants or classes of market participants. The board should not be regarded as a partner or a contractor of the market participants. Further, the board should be composed of members that are not part of the management of the Independent Transmission Provider. This Commission has the overall responsibility for the function of the wholesale electric market, including setting overall policy for the market. Independent Transmission Providers are public utilities subject to the Commission's jurisdiction under the Federal Power Act because they own, control or operate jurisdictional transmission facilities and will administer jurisdictional wholesale energy markets. In order to carry out the functions required by Standard Market Design, the board must be fully independent of any market participants. The board is responsible for overseeing the Independent Transmission Provider's administration of the tariff and market rules that have been approved by the Commission. It also must monitor the operation of the markets within its region to identify problems, *e.g.,* the ability to exercise market power, and to propose solutions. In both of these areas, the board is accountable to the Commission, not the market participants and should ensure the following: system reliability and operating efficiency, efficiently functioning markets, and short- and long-term planning objectives. Indeed, the board should ensure that any instance of perceived or real market power or market dysfunction is reported directly and immediately by the MMU to the Commission.

559. An important implication of these principles is that the board must not be a stakeholder board with industry segments given specific seats on the board. The interest of all board members should be a well-functioning market, not representation of a specific industry segment. Similarly, board members must have no financial interests in market participants so that there is no appearance of bias or benefit.

2. Stakeholder Participation

560. Stakeholders have an important role in advising the boards of Independent Transmission Providers. Most current regional organizations have established stakeholder committees that act either as advisors or in some cases vote on proposals that go

[240] *See* California Operational Audit of the California Independent System Operator issued January 25, 2002 in PA02–1–000 and Order Concerning Governance of the California Independent System Operator 100 FERC ¶61,059 (2002).

[241] *See* Avista Corporation, *et al.*., 95 FERC ¶61,114 (2001).

[242] *See* Carolina Power & Light Company, 94 FERC ¶61,273 (2001).

before the board.[243] We continue to believe that an active stakeholder process is needed and that to fully satisfy the independence principles of Standard Market Design, these stakeholder committees must be used to advise the Board of Directors rather than function as a decision making body.

561. We are concerned that the current composition of these advisory committees may not adequately represent all segments of the industry. The current structure of many ISO stakeholder committees tends to replicate the functions of vertically integrated utilities. For example, PJM currently has five classes, Generation Owners, Transmission Owners, Other Suppliers, Electric Distributors, and End-Use Customers. Four of these classes represent interests that would benefit from higher levels of demand. Only one represents customers or end-users, and none represents demand-side technologies or alternative load control services such as demand resource management. This sector structure could discourage the introduction of changes that implement new demand management technologies and services, one of the biggest potential outgrowths of the move towards a competitive market. Financial entities, which are usually financial trading firms such as banks or other financial institutions that provide the needed capital to the industry, are also poorly represented, if at all. Therefore, we propose to require that an Independent Transmission Provider approved by the Commission must have at a minimum committees that reflect six stakeholder classes: (1) Generators and marketers, (2) transmission owners (this sector would include vertically integrated utilities), (3) transmission-dependent utilities,[244] (4) public interest groups (*e.g.*, consumer advocates, environmental groups, citizen participation), (5) alternative energy providers (*e.g.*, distributed generation, demand response technologies, renewable energy), and (6) end-users and retail energy providers (*i.e.*, load-serving entities that do not own transmission or distribution assets). In addition, we propose to require that there be a separate Regional State Advisory Committee that would advise the board. We believe that six stakeholder classes provides better representation for certain market participants, *e.g.*, transmission-dependent utilities and new technologies that have not been adequately represented in the past. Also, we propose that a company (including all of its affiliates) may have a representative in only one stakeholder sector. For example, a vertically integrated utility that has a marketing affiliate would have to choose whether it would be represented in the transmission owner sector or the generator/marketer sector. This will prevent large corporations from dominating sector representation by placing their affiliates and subsidiaries in several sectors. Initially, the company would be allowed to choose which sector it wished to join. However, requests to change sectors may be subject to limitations to avoid frequent changes that could be used to affect sector voting results for advisory actions recommended to the board. For example, the corporation may be required to decide which sector it will join on an annual basis. This would allow corporations to change sectors to reflect changes in corporate business models, but not allow frequent changes that could be used to change voting results on particular proposals. We also seek comment on whether or under what circumstances, a stakeholder class should be able to take an issue directly to the board outside the stakeholder process.

3. Initial Selection Process for Board of Directors

562. The initial selection process for the Board of directors must be structured to ensure that board members are independent and have expertise in a variety of transmission and electric market areas. We propose that the following process be used.[245]

563. First, the qualifications of the board members should be established. We believe it is important that the qualifications be more widely focused than just experience with electric transmission systems. Experience in additional areas such as risk management, generation planning and operation, or technology and innovation would provide the board with a wider background of knowledge in areas crucial to market development. We propose that board candidates be required to have experience in one or more of these fields: senior corporate leadership of a major publicly traded company; professional disciplines of finance, accounting, or law; electrical engineering; regulation of utilities; transmission system operation or planning; trading or risk management; information technology; and generation planning or operation. The candidate could have experience in the electric industry in either an Investor-Owned Utility or public power entity. The objective is to have a board that collectively possesses experience in many, if not all, of these areas.

564. Board members or their immediate families should not have current or recent ties (within the last two years) as a director, officer or employee of a market participant in the region or its affiliates. Board members or their immediate families should also not have direct business relationships with market participants or their affiliates. Finally, to the extent that the board member owns stocks or bonds of companies that are market participants, these must be divested within six months of being elected to the board. Prior to divestiture, the board member would not be able to participate in any decisions affecting that market participant or its affiliates. These requirements are necessary to ensure that the board member does not have any financial interest in a market participant that could influence the board member's decision. We propose that board members, their immediate families and senior management be required to fill out annual financial disclosure statements to ensure that there is no conflict of interest. The financial disclosure statements would be available for audit by the Commission.

565. Second, a nationally recognized search firm should be retained by the nominating committee to identify candidates that satisfy these criteria. The search firm should supply at least two names for each available board seat. The use of a nationally recognized search firm to develop the list of potential board members helps ensure the integrity of the process since the search firm would not have a financial interest in proposing candidates that represent specific market participants or classes of market participants. The search firm should not have a significant ongoing business relationship with the market participants in the region. The search firm must disclose to the nominating committee any ongoing business relationships it has with market participants in the region.

[243] In Order No. 2000, 23 required that these types of stake holder committees be advisory in RTOs. This meant that the board would have the ability to propose changes to market rules to the commission whether those changes we approved by the stakeholder committees. We propose to continue this policy for Independent Transmission Providers.

[244] These are utilities that must take transmission service from public utilities to provide retail service to their customers.

[245] We are not proposing any specific requirements on the number of board members. We anticipate that the board will have between five and nine members, which is consistent with the current size of the Board of Directors for ISOs and proposed for RTOs.

566. A nominating committee composed of two members from each of the stakeholder classes would be formed to review the list of candidates presented by the search firm. The nominating committee would vote for the individual board candidates as follows. Each nominating committee member would have the right to cast votes equal to the number of open board seats. A member shall not cast more than one vote for any one candidate and is not required to cast all of its votes.

567. Board seats are filled by a simple majority. Candidates with the highest vote totals are elected to open board seats. Ties for the last open board seats will have a runoff subject to the same rules as the initial selection process. The elected board members would vote to designate one of the members as Chairman of the Board. We seek comment on whether the Chief Executive Officer of the Independent Transmission Provider should be a non-voting member of the board.

568. We recognize that allowing a vote on candidates by stakeholders could be perceived as allowing a sector to dominate the board selection process or result in less than a fully independent board. While we recognize the concern, we believe that it is important that stakeholders have a voice in the selection process. We do not believe that it is the Commission's role to be the primary decision-maker in determining the candidates that are selected for the board. We seek comment on what protections should be built into the selection process to ensure that a class of market participants does not dominate the stakeholder voting process. Nevertheless, we solicit comment on whether to require the nominating committee to vote on an entire slate of candidates rather than on individual candidates.

4. Succession of Board Members

569. The governance process also needs to include ongoing procedures for the selection of new board members. We believe that the process should seek to maintain a degree of continuity of board membership to ensure stability and consistency in decisionmaking, while at the same time ensuring that the board does change membership over time to allow the introduction of new viewpoints and encourage innovation.

570. To accomplish these two objectives, we propose that the board members have staggered terms. Approximately half of the first board should have initial terms of four years. The remaining board members should have initial terms of three years. All subsequent board members' terms will be for four years. The staggered terms will provide a degree of continuity to the board in its decision making process. We seek comment on whether the proposed staggered terms would lead to too rapid a turnover in the composition of the board. Board members would be permitted to serve no more than two consecutive terms. This limitation will ensure that there will be a change in board membership over time to allow for the introduction of board members with different experience.

571. The same process that was used to select the initial Board of Directors would be used in the selection process for subsequent board members in the case of resignation, death or removal for cause. Namely a nationally recognized search firm would be retained to identify board candidates. A nominating committee would be formed to review the list of candidates and propose new board members.

572. When the first set of board members terms start expiring a two stage process would be used for electing board members. First, existing board members whose terms are expiring would indicate whether they wished to remain on the board for a second term. The stakeholders would vote on whether these existing board members would remain on the Board of Directors. Second, if there were any remaining vacancies, then a search firm would be retained to provide candidates for the vacant seats on the Board of Directors. The same process that was used for filling the initial Board of Directors would be used for filling these vacancies.

5. Mergers of Independent Transmission Providers

573. We propose the following initial governance structure in the event of a merger of ISOs, RTOs or Independent Transmission Providers. Initially, the board members of the newly formed entity will be comprised of a number of board members from each of the respective organizations in addition to new members. We propose that there should be equal representation from each former organization plus an equal number of new board members.[246] This type of composition will provide the new merged Independent Transmission Provider with the expertise, knowledge and experience during start-up while new board members would bring fresh ideas and perspective. The members from the existing boards will be chosen by their respective boards, after consultation with stakeholders on the expertise and experience needed by the new organization.

574. A nominating committee will nominate all candidates (except the initial members that originate from the original boards of ISOs, RTOs or Independent Transmission Providers) for the initial election of new board members. The initial nominating committee will be composed of two board members from each of the respective merging organizations and the Chairs of two committees representing market operations, reliability and/or management.

M. System Security

575. System security is critical to the reliable operation of the interstate transmission grid. Wholesale electric grid operations are highly interdependent, and a failure of one part of the generation, transmission, or grid management system can compromise the reliable operation of a major portion of the regional grid. The wholesale electric market relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch and market software and systems. Because of this mutual vulnerability and interdependence, it is necessary to safeguard the electric grid and market resources and systems by establishing minimum standards for public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce as well as entities that use these facilities.

576. NERC's Critical Infrastructure Protection Advisory Group has recently developed a set of recommended minimum requirements (standards) for securing information assets that support grid reliability and market operations and the physical environments in which these information assets operate. These standards are designed to ensure that the entity has a basic security program protecting the electric grid and market from the impact of acts, either accidental or malicious, that could cause wide-ranging harmful impacts on grid operations. These standards would be administered through an annual self-certification due January 31, 2004, and every January 31 thereafter. The proposed form for the self-certification is attached as Appendix G.

577. We propose to require that all public utilities that have tariffs on file with the Commission must file the self-certification by January 31, 2004, and every January 31 thereafter. Additionally, on and after February 1, 2004, as a condition of receiving

[246] For example, a nine member board for a merger of two RTOs would reflect 3 members from each of the former RTOs plus three new members.

transmission service provided by a public utility that owns, controls or operates transmission facilities, a customer must demonstrate that it has a basic security program in place. The customer can satisfy this requirement by supplying the public utility with a copy of the executed self-certification form. In the case of entities seeking transmission service that are not public utilities subject to the Commission's regulations, the entity would still be required to demonstrate that it has a basic security program in place to receive transmission services. This could be done by supplying the transmission provider with an executed self-certification using the Commission's form. Alternatively, the transmission provider and the customer could develop an alternative arrangement for ensuring that the customer has a basic security program in place.

578. Finally, when the SMD Tariff is implemented, we propose to extend the requirement to cover the additional services being provided by the Independent Transmission Provider. At that time, any customer seeking to buy or sell through the markets operated by the Independent Transmission Provider or take transmission service under the Network Access Service would be required to demonstrate that it has a basic security program in place.

579. We expect that these standards will be revised and refined over time in light of changes in technology and operational experience with the standards. Therefore, the regulations will also identify the specific version number of the system security standards. When NERC revises the standards, the revisions will be filed with the Commission. The Commission will issue a Notice that it is considering revising the updated system security standards, and we will seek comments on the proposed changes. These security standards for electric market participants can be found in Appendix G, along with the proposed self-certification form, discussed above.

V. Implementation

580. The Commission proposes to find in the Final Rule that rates, terms and conditions of transmission service and wholesale electric sales that do not comport with the regulations adopted by the Final Rule are unjust, unreasonable or unduly discriminatory. Many of the elements included in Standard Market Design will require computer software development and changes that public utilities may not be able to fully implement for a couple of years. The Commission's objective is to have Standard Market Design implemented on all jurisdictional transmission systems no later than September 30, 2004, or such time as the Commission may establish. The Commission does not believe it is in the public interest to delay implementation of the remedial action to cure undue discrimination or to develop necessary infrastructure until the time when all of the software changes necessary for standard market design are completed. Consequently, the Commission proposes a multi-step process that will be used to bring these rates, terms and conditions of service into conformity with the regulations.

30 Days After Effective Date of Final Rule

581. The Commission will require all public utilities that own, control or operate interstate transmission facilities to begin discussions with stakeholders and state representatives within 30 days after the effective date of the Final Rule about how they will implement the transition process and comply with the requirements of the Final Rule. These discussions should address selection of an Independent Transmission Provider that will manage the transmission facilities, establishment of a regional state advisory committee, development of a regional transmission planning and expansion program, development of a long-term resource adequacy requirement and identification of areas such as load pockets where mitigation or appropriate infrastructure will be necessary.

July 31, 2003

582. The Commission recognizes that it has accepted many changes to the *pro forma* tariffs of individual transmission providers that deviate from the *pro forma* tariff contained in Order No. 888. To the extent these changes involve bundled retail load or give preference to either native load customers or the transmission provider's use of its system, we propose to direct the transmission provider to eliminate them. We have revised the Order No. 888 *pro forma* tariff to place bundled retail load under the open access transmission tariff, and to eliminate undue preferences for native load customers and the transmission owner's use of its own system.[247] The revised Order No. 888 *pro forma* tariff, which is referred to as the Interim Tariff in this proposed rule, is attached as Appendix A. Pursuant to section 206 of the FPA, we propose to require all public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to file the Interim Tariff, no later than July 31, 2003. The Interim Tariff will become effective on September 30, 2003, after the peak summer season.

583. Although a transmission tariff rate is already in effect for all public utilities that own, operate or control facilities used for the transmission of electric energy in interstate commerce, we acknowledge that changes to individual utility rates may be necessary as a result of the changes to non-rate terms and conditions that the Interim Tariff requires. Should a public utility determine that such rate changes are warranted by the new non-rate terms and conditions, it may file a new rate proposal pursuant to FPA section 205, no later than July 31, 2003. We will impose a blanket suspension on any such filings that we receive and make them effective, subject to refund, 61 days after they are filed.

584. We also propose a new tariff (SMD Tariff), attached as Appendix B, to supersede the Interim Tariff and implement Standard Market Design. The new SMD Tariff includes many areas in which the Independent Transmission Provider would propose provisions consistent with the policy framework set forth in the Final Rule, but designed to meet the specific circumstances of the region. We propose to give regions discretion in developing a transition program for existing contracts that is consistent with the guidelines set forth in the Final Rule.

585. The Commission recognizes that public utilities will need time to ensure that transmission facilities are operated by an Independent Transmission Provider, implement Network Access Service, establish day-ahead and real-time markets, adopt LMP for congestion management, incorporate market power mitigation measures customized for the region, develop a market monitoring program and develop a resource adequacy requirement for the region. Thus, for these requirements the Commission proposes a process for implementation that provides an opportunity for active participation by state representatives and market participants and that gives the Commission opportunities to review progress and require changes if sufficient progress is not being made.

586. To implement the requirements of Standard Market Design, we propose to require every public utility that owns, controls or operates facilities used for the transmission of electric energy in

[247] The public utility would make the revisions to its currently effective Open Access Transmission Tariff. The changes to the Order No. 888 tariff are intended to identify the changes that must be made.

interstate commerce to select an Independent Transmission Provider to operate its transmission facilities. A public utility may meet this requirement by: (1) Itself satisfying the definition of Independent Transmission Provider; (2) turning over its transmission facilities to a Commission-approved RTO that meets the definition of Independent Transmission Provider; or (3) contracting with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

587. The Commission will require all public utilities that own, operate or control interstate transmission facilities to file an Implementation Plan for compliance with the regulations no later than July 31, 2003. In the Implementation Plan, the public utility must identify the independent entity that will serve as the Independent Transmission Provider for the transmission facilities that the public utility owns, controls or operates. (A public utility that is already a member of an entity that satisfies the definition of Independent Transmission Provider may request a waiver from this requirement in its Implementation Plan filing.) Additionally, the Implementation Plan must include time lines and a proposal for compliance with the long-term resource adequacy requirements of the Final Rule. Further, the Implementation Plan must identify the software vendor(s) that the public utility will use for implementation of Standard Market Design and a time line that identifies implementation milestones and indicates the projected timing of their completion. The Commission wants to ensure that the cost of implementation of Standard Market Design is reasonable, and intends to closely monitor the expenditures incurred to implement the Final Rule. Therefore, we propose to require that all public utilities include in their Implementation Plan a detailed estimate of their projected cost of implementing the Final Rule. The estimate should include projected software costs as well as other costs that the public utility may incur. The public utility will also be required to file status reports on the Implementation Plan on a quarterly basis. The Commission will review the Implementation Plans and quarterly reports to ensure compliance with the regulations. Also, the Commission will establish appropriate procedures, if needed, for resolving concerns of state representatives and market participants.

588. The Commission recognizes that some public utilities will be able to implement Standard Market Design more quickly than others. The dates proposed in the Implementation Plan should reflect the level of changes that are required. The Commission intends to be flexible in setting compliance dates for Standard Market Design. The Commission expects that those public utilities that do not require significant changes could implement Standard Market Design much sooner than others. While the Commission's objective is to have Standard Market Design in place everywhere by September 30, 2004, it will consider requests to extend this date if the public utility can document that additional time is necessary.

589. Finally, the public utility must cooperate with others in its region to have a Regional State Advisory Committee in place by July 31, 2003.

Six Months After Effective Date of Final Rule

590. The Commission proposes to require all public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to begin a regional transmission planning process within six months and produce a plan within one year of the effective date of the Final Rule. This will be an intermediate step in the process of satisfying the planning and expansion requirements contained in section 35.34(k)(7) of the Commission's regulations.[248] The Independent Transmission Provider will take over this process when it becomes operational.

December 1, 2003 and September 30, 2004

591. Pursuant to section 206 of the FPA, by December 1, 2003 all Independent Transmission Providers will be required to file the SMD Tariff, including language that explains the Independent Transmission Provider's proposals for market monitoring, market power mitigation, long-term resource adequacy, transmission planning and expansion, transmission pricing and any changes to the SMD Tariff necessary to accommodate regional needs. The filing must also indicate the date, which must be no later than September 30, 2004, or such date as the Commission may establish, when the Independent Transmission Provider will be able to fully implement Standard Market Design. The Commission must approve the tariff filing before the Independent Transmission Provider will be able to implement Standard Market Design. We anticipate acting on these filings on a timely basis so that the Independent Transmission Providers will know several months before the planned implementation date any changes that are required in these filings.

592. As a result of the changes required by the Final Rule, the Independent Transmission Provider or transmission owners may believe that other changes are needed in their transmission rates for jurisdictional service. Transmission owners and Independent Transmission Providers should file these types of changes under section 205 of the FPA at least 60 days prior to the date on which they propose to implement Standard Market Design. The Commission intends the implementation process to be a collaborative one. The Commission directs public utilities to meet with stakeholders and state commissions on a regular basis to discuss the changes that are necessary to comply with the Final Rule. Based on the filings that are received, the Commission may also establish technical conferences, mediation efforts or other procedures as necessary to ensure that all public utilities that own, control or operate interstate transmission facilities will be operating under Standard Market Design no later than September 30, 2004, or such time as the Commission may establish.

593. Further, the Commission intends this phased compliance process to encourage joint compliance filings. Public utilities may submit a single, joint application to meet the requirements of Standard Market Design, and Independent Transmission Providers may make necessary filings on behalf of their public utility members. Such joint filings may streamline the compliance process and reduce its costs.

January 31, 2004

594. The Commission proposes to require all public utilities to provide assurances to the Independent Transmission Provider with which they are affiliated that the public utilities comply with minimum security standards. We propose to require public utilities that have transmission tariffs on file with the Commission to file the self-certification of compliance with security standards that is attached as Appendix G. The self-certification must be submitted by January 31, 2004, and every January 31 thereafter. On and after February 1, 2004, any transmission customer (including a non-jurisdictional entity) that seeks to receive transmission service from a public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must provide assurances to the transmission provider that it has a basic security system in

[248] 18 CFR 35.34(k)(7) (2002).

place. This may be done by providing the transmission provider with a copy of the executed self-certification form, or the transmission provider and customer may make alternate arrangements. Following the implementation of Standard Market Design, we propose to extend this self-certification requirement to apply to any customer seeking to buy or sell through the Independent Transmission Provider's markets or take Network Access Service.

VI. Public Comment Procedures

595. The Commission invites interested persons to submit comments, data, views and other information concerning matters set out in this proposed rule. To facilitate the Commission's review of the comments, the Commission requests commenters to provide an executive summary (not to exceed ten pages) of their positions. To the greatest degree possible, commenters should use the topic headings that the proposed rule uses and arrange their comments in the order of topics presented in this proposed rule, and cite the specific referenced paragraph numbers. Commenters should identify separately any additional issues that they may wish to address. Commenters should double-space their comments. Comments must refer to Docket No. RM01–12–000, and may be filed on paper or electronically via the Internet. The Commission must receive all comments no later than October 15, 2002. Comments should include an executive summary that should not exceed ten pages. Those filing electronically do not need to make a paper filing. Reply comments will not be entertained.

596. Those making paper filings should submit the original and 14 copies of their comments to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

597. The Commission strongly encourages electronic filings. Commenters filing their comments via the Internet must prepare their comments in WordPerfect, MS Word, Portable Document Format, or ASCII format (*see http://www.ferc.gov/documents/electronicfilinginitiative/efi/efi.htm,* in particular ''User Guide''). To file the document, access the Commission's Web site at *www.ferc.gov* and click on ''e-Filing'' and then follow the instructions for each screen. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgment to the sender's e-mail address upon receipt of comments. User assistance for electronic filing is available at 202–208–0258 or by e-mail to *efiling@ferc.gov.* Do not submit comments to the e-mail address.

598. The Commission will place all comments in the Commission's public files and they will be available for inspection in the Commission's Public Reference Room at 888 First Street, NE., Washington, DC 20426, during regular business hours. Additionally, all comments may be viewed, printed, or downloaded remotely via the Internet through FERC's home page using the FERRIS link.

VII. Regulatory Flexibility Act

599. The Regulatory Flexibility Act [249] requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities.

600. This rule applies to public utilities that own, control or operate interstate transmission facilities, not to electric utilities per se. The total number of public utilities that, absent waiver, would have to modify their current open access transmission tariffs by filing the Interim Tariff is 176.[250] Of these only 6 public utilities, or less than two percent, dispose of 4 million MWh or less per year.[251] We do not consider this a substantial number, and in any event, these small entities may seek waiver of the Standard Market Design Final Rule requirements.[252]

601. With respect to the Interim Tariff, the Commission will specify precisely the terms and conditions that public utilities will have to incorporate into their existing tariffs, and this will considerably reduce the burden of modifying transmission tariffs. In order to implement the SMD Tariff, every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must (a) meet the definition of Independent Transmission Provider, (b) turn over the operation of its transmission facilities to a regional transmission organization that meets the definition of Independent Transmission Provider, or (c) contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities. We do not expect that any entity that must file an SMD Tariff would be a small entity as defined by the Regulatory Flexibility Act.

602. We do not, therefore, believe that the requirement of filing the Interim Tariff and SMD Tariff will impose a significant economic impact on small entities. Consequently, the Commission certifies that this proposed rule will not have a significant economic impact upon a substantial number of small entities.

VIII. Environmental Statement

603. In furtherance of the National Environmental Policy Act of 1969, the Commission will prepare an environmental assessment (EA) that will consider the environmental impacts of the proposed rule. A notice of intent to prepare the EA, including a request for comments on the scope of the EA and notice of a public scoping meeting was issued on July 26, 2002.[253]

IX. Public Reporting Burden and Information Collection Statement

604. The Commission is submitting the following collections of information contained in this proposed rule to the Office of Management and Budget (OMB) for review under section 3507(d) of the Paperwork Reduction Act of 1995. The Commission identifies the information provided under Part 35 as FERC–516.

605. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimates, ways to enhance the quality, utility and clarity of the information that the Commission will collect, and any suggested methods for minimizing respondent's burden, including the use of automated information techniques.

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[249] 5 U.S.C. 601–612 (1994).

[250] The sources for this figure are FERC Form No. 1 and FERC Form No. 1–F data.

[251] *Id.*

[252] 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) (1994); 15 U.S.C. 632(a)(1) (1994). In *Mid-Tex Elec. Coop.* v. *FERC,* 773 F.2d 327, 340–343 (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 Standard Market Design rules 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.

[253] Notice of Intent to Prepare an Environmental Assessment and Request for Comments on the Scope of Issues to be Addressed for the Proposed Rulemaking on Electricity Market Design and Structure, Docket No. RM01–12–000 (July 26, 2002).

The burden estimates for complying with this proposed rule are as follows:

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–516	176	1	*1,199	211,024
	176	4	3	2,112
	12	1	164	1,968
Totals			1,366	215,104

*Rounded off.

Respondent	Document	Recipient	Required content	Hours per response
All public utilities that own, operate or control transmission facilities.	(no document required).	Stakeholders and state representatives.	Public utilities must discuss with stakeholders and state representatives how they will implement the transition process and comply with the Final Rule: 1. Selection of Independent Transmission Provider. 2. Establishment regional state advisory committee. 3. Development of regional transmission planning /expansion program. 4. Development of a long-term resource adequacy requirement. 5. Identification of areas where mitigation or appropriate infrastructure will be needed.	430 hours
All public utilities that own, operate or control transmission facilities.	Revisions to Order No. 888 tariff (Interim Tariff) or request for waiver of this requirement.	FERC	Tariff language to place service to bundled retail customers under OATT, eliminate preferences for native load and for a transmission provider's own use of its system.	182 hours
All public utilities that own, operate or control transmission facilities.	Implementation plan for compliance with proposed regulations.	FERC	1. Identify Independent Transmission Provider (or request waiver of this requirement). 2. Time lines and proposed procedures for regional transmission planning process. 3. Time line and proposal for compliance with long-term resource adequacy requirements. 4. Identify software vendor(s) to be used for implementation of SMD. 5. Implementation time line showing projected timing and completion of milestones for software development. 6. Detailed estimate of costs of implementing SMD.	193 hours
Public utilities	Quarterly Reports	FERC	Implementation Plan Status	3 hours
Transmission Provider	Proposed tariff language.	FERC	1. SMD Tariff, including proposed language for market monitoring and market power mitigation; long-term resource adequacy; transmission planning and expansion; changes to SMD Tariff needed to accommodate regional needs. 2. Date by which transmission provider will fully implement SMD.	124 hours
Transmission Provider	Section 205 filing requesting approval of adjustment of revenue requirement (optional).	FERC	Section 205 filing demonstrating that transmission provider's revenue requirement should be adjusted to recover additional costs associated with conversion pre-Order No. 888 contracts to service under new tariff and allocation of congestion revenue rights directly to customers.	*If respondent decides to submit a § 205 filing, the burden is already covered under existing requirements

Respondent	Document	Recipient	Required content	Hours per response
Transmission Provider/participating generators.	Participator Generator agreements.	FERC	1. Identify noncompetitive conditions in which generator would have to selfschedule or supply all capacity to spot markets. 2. Specify bid caps that would apply to generator's day-ahead and real-time bids.	34 hours
Transmission Provider	Reliability proposals	FERC	Proposal regarding implications of each reliability procedure (e.g. curtailment) for market prices in energy and ancillary services markets.	63 hours
Transmission Provider	Transmission Expansion Plan.	FERC	Have in place a regional transmission planning process and complete first transmission expansion plan pursuant to 18 CFR 35.34(k)(7).	120 hours
Market Monitoring Unit	Initial competitive market analysis.	FERC	1. Identify load pockets that require different bid mitigation triggers. 2. Identify generators that may be required for reliability.	78 hours
Market Monitoring Unit	Annual report on market operations.	FERC & Independent Transmission Provider's Governing Board.	1. General description—market operations, supply and demand, market prices. 2. Analysis of market structure and participant behavior. 3. Evaluation of effectiveness of mitigation measures taken. 4. Overall assessment of market efficiency. 5. Evaluation of barriers to entry for generating, demand-side, and transmission resources. 6. Recommended changes to market design or market power mitigation measures to improve market performance.	86 hours
Load serving entities	Resource adequacy report.	RTO	Report and document plan to meet share of regional adequacy requirement.	38 hours
RTOs	Regional Demand Forecast.	RTO	Regional demand forecast for its region for the planning horizon.	To be determined
All public utilities with a transmission tariff on file with the Commission.	Self-certification of compliance with system security standards.	FERC	Completed and executed form contained in Appendix G to Notice of Proposed Rulemaking.	2 hours
All public utilities with a transmission tariff on file with the Commission.	Annual recertification of compliance with system security standards.	FERC	Completed and executed form contained in Appendix G to Notice of Proposed Rulemaking.	.5 hours

Total Annual Hours for Collection (reporting + record keeping (if appropriate) = 215,104 hours.

Information Collection Costs

606. Because of the regional differences and the various staffing levels that will be involved in preparing the documentation (legal, technical and support) the Commission is using an hourly rate of $50 to estimate the costs for filing and other administrative processes (reviewing instructions, adjusting existing ways to comply with previously applicable instructions or requirements, training personnel to be able to respond to the information collection, searching data sources, completing and transmitting the collection of information and conducting outreach sessions with all affected entities) associated with this proposed rule. The estimated cost is anticipated to be $10,755,200 (215,104 hours × $50) for this portion of the rule.

607. In addition, there is a separate component that must also be considered when implementing the requirements of this proposed rule, the costs for information technology (IT) needed to implement the SMD Tariff. The number of entities to be impacted at this phase of the rule's implementation will be fewer than at the Interim Tariff stage, but is still unknown at this time. Further, several entities are already developing or employing software that may be sufficient to implement the SMD Tariff, and the entities' software packages are at different stages of development. There are also regional differences to consider (as noted above) with respect to labor compensation. For these reasons, the Commission seeks comments on the anticipated costs for IT development associated with this proposed rule. When preparing their estimates, commenters should take into consideration design, procurement and operation costs for the following: (1) Data collection systems (including monitors, detection systems, control

systems and other equipment necessary to obtain information or data of interest, as well the facilities and equipment necessary to house and operate such systems); (2) data management systems necessitated by the data collection(s) (including computers and other hardware, programs and other software, storage media and facilities); and (3) data reporting systems necessitated by the information collection (including electronic links, installing and operating the reporting components of an information management system and the burden of maximizing public accessibility). These investments in information technology are for systems whose useful lifetime exceeds the expiration of the data collection (which must be reviewed and approved by OMB after three years), so the costs for this reporting burden needs to be estimated based on the costs of a longer lived investment. OMB regulations require OMB to approve certain information collection requirements imposed by agency rule.[254] Accordingly, pursuant to OMB regulations, the Commission is providing notice of its proposed information collections to OMB.

Title: FERC–516, Electric Rate Schedule Filings.

Action: Proposed Data Collections.

OMB Control No.: 1902–0096.

The applicant shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

Respondents: Business or other for profit.

Frequency of Responses: One time.

Necessity of Information: The proposed rule would revise the requirements contained in 18 CFR part 35. The Commission is seeking to standardize wholesale electric market design and transmission service. The Commission proposes to develop a standardized set of electricity market rules that reflects many of the recommendations and suggestions elicited from all market participants.

608. The proposed SMD rules are intended to have a generally positive impact on these market participants. For example, the proposed SMD rules will facilitate direct dealings between market participants who want to secure long-term bilateral power supply arrangements. The proposed SMD rules will also facilitate short-term transactions that are made in the spot market to make up for imbalances (differences) between scheduled electricity supplies that were matched to projected load levels, and the load levels that actually develop. Through these proposed SMD rules, sellers will be able to more effectively sell into the market and buyers will be able to more efficiently buy from the market because they will not need to be directly matched up at the last minute on a real-time hourly and day-ahead basis. In addition, the proposed SMD rules will bolster the ability of many smaller customers, as well as larger customers, to profitably participate in programs designed to encourage reductions in loads to offset electricity supply shortages. Finally, the proposed SMD rules will foster the trading of transmission rights among transmission customers that will allow them to hedge against transmission congestion surcharges.

609. Up to 176 public utilities that own, operate or control transmission would be required to implement the Commission's SMD Rule. The revised open access transmission component of the SMD Rule would be incorporated as an interim amendment to the existing transmission tariffs of all jurisdictional transmission providers operating in interstate commerce. Independent Transmission Providers would also be required to file SMD Tariffs contained in the Final Rule to implement Network Access Service and Standard Market Design. To the extent an affected public utility participates in an RTO, or contracts with an Independent Transmission Provider, the RTO or Independent Transmission Provider would make the required filing on behalf of the affected public utility. Public utilities also will be permitted to file Implementation Plans jointly with other utilities. Further, the Commission proposes to entertain requests for waivers of the requirement to make compliance filings. These features of the proposed rule would lessen the incidence of SMD compliance filings. We have estimated for purposes of this analysis that RTOs and ITPs may number from 5 to 12 entities in the lower 48 states.

Internal Review: The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements. The Commission's Office of Markets, Tariffs and Rates will use the data included in filings under Sections 203 and 205 of the Federal Power Act to evaluate efforts for the interconnection and coordination of the United States electric transmission system and to ensure the orderly formation and operation of a standard design in wholesale electric transmission markets, as well as for general industry oversight. These information requirements conform to the Commission's plan for efficient information collection, communication, and management within the electric power industry.

610. 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, Capital Planning and Policy Group, Phone: (202) 502–8415, fax: (202) 208–2425, e-mail: *michael.miller@ferc.gov.*]

611. Please send your comments concerning the collection of information(s) and the associated burden estimates to the contact listed above and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–7856, fax: (202) 395–7285].

X. Document Availability

612. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's home page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m., to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

613. From FERC's home page on the Internet, this information is available in the Federal Energy Regulatory Records Information System (FERRIS). The full text of this document is available on FERRIS in PDF and WordPerfect format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number of this document, excluding the last three digits in the docket number field.User assistance is available for FERRIS and the FERC's Web site during normal business hours from our Help Line at (202) 208–2222 (e-mail to *WebMaster@ferc.gov*) or the Public Reference at (202) 208–1371 Press 0, TTY (2020) 208–1659 (e-mail to *public.reference.room@ferc.gov*).

List of Subjects in 18 CFR Part 35

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

[254] *See* 5 CFR 1320.11 (2002).

By direction of the Commission.

Commissioner Breathitt concurred with a separate statement attached.

Magalie R. Salas,

Secretary.

In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter I, Title 18, *Code of Federal Regulations*, as follows.

Regulatory Text

PART 35—FILING OF RATE SCHEDULES

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. 7101–7352.

2. Part 35 is amended by adding a new Subpart G, Procedures and Requirements Regarding Non-Discriminatory Open Access Transmission Services and Standard Market Design, including new §§ 35.35, 35.36, 35.37 and 35.38 to read as follows:

Subpart G—Procedures and Requirements Regarding Non-Discriminatory Open Access Transmission Services and Standard Market Design

Subpart G—Procedures and Requirements Regarding Non-Discriminatory Open Access Transmission Services and Standard Market Design

§ 35.35 Standard Market Design Tariff.

(a) Applicability. This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce and to any Independent Transmission Provider.

(b) Definitions—

(1) *Independent Transmission Provider.* As used herein the term *Independent Transmission Provider* shall mean any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure), and that is independent (*i.e.*, has no financial interest, either directly or through an affiliate, as defined in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. 79b(a)(11)), in any market participant in the region in which it provides transmission services or in neighboring regions).

(2) *Market Participant.* As used herein the term *Market Participant* shall mean:

(i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the Independent Transmission Provider, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Independent Transmission Provider's actions or decisions; and

(ii) Any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the Independent Transmission Provider's actions or decisions.

(c) Non-discriminatory open access transmission services and standard market design.

(1) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, shall provide non-discriminatory open access services through the interim tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____(Final Rule on Electricity Market Design and Structure) no later than September 30, 2003. Such tariff shall remain on file with the Commission until it is superseded by the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure).

(2) To implement the requirements of Non-Discriminatory Open Access Transmission Services and Standard Market Design, every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must meet the definition of Independent Transmission Provider, turn over the operation of its transmission facilities to a regional transmission organization, as defined in § 35.34(b)(1) of this title, that meets the definition of Independent Transmission Provider, or contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

(i) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce as of [effective date of Standard Market Design Rule] must comply with this requirement by September 30, 2004, or such other date as determined by the Commission. Such public utility must inform the Commission which Independent Transmission Provider will operate the public utility's transmission facilities, and provide further information about its plans to implement Standard Market Design as specified in Order No. ____, FERC Stats. & Regs. ¶ ____, no later than July 31, 2003. Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce after the effective date of this rule must comply no later than 60 days prior to the time its facilities are used for transmission in interstate commerce.

(ii) A public utility that is a member of an approved regional transmission organization or an independent system operator or other entity that meets the definition of Independent Transmission Provider may file a request for a waiver of the filing requirements of this paragraph on the ground that it has already complied with the requirement. An application for a waiver must be filed no later than July 31, 2003, or no later than 60 days prior to the time the public utility's transmission facilities are used for transmission in interstate commerce.

(3) Pursuant to section 206 of the Federal Power Act, any entity that meets the definition of Independent Transmission Provider must file with the Commission a tariff of general applicability for the provision of transmission services, including ancillary services and the administration of the day-ahead and real-time energy and ancillary services markets. Such tariff must be the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure) or such other open access tariff as may be approved by the Commission consistent with Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure). Such tariff must include proposed language that explains the Independent Transmission Provider's proposals for market monitoring, market power mitigation, long-term resource adequacy, transmission planning and expansion, transmission pricing, changes to the pro forma tariff necessary to accommodate regional needs, and further information as specified in the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure). The filing also shall specify the date on which the Independent Transmission Provider proposes to implement Standard Market Design.

(4) The Independent Transmission Provider shall file, pursuant to section

205 of the Federal Power Act, any changes to its transmission rates necessary to implement Standard Market Design, no later than 60 days prior to the date on which it proposes to implement Standard Market Design, or 60 days prior to the time its facilities are used for transmission in interstate commerce.

(5) One or more public utilities may jointly file an application to meet the requirements of this paragraph.

(6) An Independent Transmission Provider may make necessary filings on behalf of public utilities required to meet the requirements of this paragraph.

(7) The interim tariff and pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure) will not apply to transmission of electric energy pursuant to contracts that were executed on or before July 9, 1996 and remain in effect as of [effective date of Standard Market Design Rule]. Customers under such contracts may elect to convert their contracts, consistent with their contract terms, to service under the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure) at any time after [effective date of Standard Market Design Rule].

(8) Waivers. A public utility subject to the requirements of this section may file a request for waiver of all or part of the requirements of this section, for good cause shown. An application for waiver must be filed no later than [effective date of Standard Market Design Rule], or no later than 60 days prior to the time the Independent Transmission Provider would otherwise have to comply with the requirement.

(d) 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 provides transmission service that is comparable to the service that the non-public utility provides itself.

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 case 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 order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access tariff, for good cause shown. An application for waiver may be filed at any time.

(3) If a non-public utility has on file with the Commission, as of [effective date of Standard Market Design Rule], a reciprocity tariff accepted by the Commission, the non-public utility is not required to make a filing under paragraph (d) of this section.

§ 35.36 Market monitoring and market power mitigation.

(a) The Independent Transmission Provider must have a market monitoring unit that is independent of the Independent Transmission Provider's management and that is accountable to the Commission. The market monitoring unit will provide information and recommendations to the Commission and the governing board of the Independent Transmission Provider.

(b) The market monitoring unit will monitor all markets run by the Independent Transmission Provider and the operation of the transmission grid for exercises of market power, flaws in the Independent Transmission Provider's tariff rules or operations that contribute to economic inefficiency, and market participants' compliance with the Independent Transmission Provider's tariff. The market monitoring unit also shall perform further duties as instructed by the Commission.

(c) The market monitoring unit will report at least annually on the structure and performance of the markets in the Independent Transmission Provider's region. The report must include, at a minimum: a description of market operations, supply and demand, and market prices; an structural analysis of the market, including an evaluation of barriers to entry; an assessment of market performance, including an assessment of market participant behavior; an evaluation of the effectiveness of the existing market power mitigation; and recommendations for improving the market design or market power mitigation measures to improve the efficiency of the market. The market monitoring unit also shall provide further reports as directed by the Commission.

(d) The Independent Transmission Provider must include in its tariff provisions requiring market participants, as a condition of participating in the markets operated by the Independent Transmission Provider and using the interstate transmission facilities operated by the Independent Transmission Provider.

(1) To agree to provide to the market monitoring unit all information and data requested by the market monitoring unit to perform its functions under these rules and the Independent Transmission Provider's tariff, and

(2) To agree to penalties specified in the Independent Transmission Provider's tariff for the violation of any tariff provisions.

(e) The market monitoring unit is responsible for administering the market power mitigation provisions of the Independent Transmission Provider's tariff.

§ 35.37 Long-term electric energy resource adequacy.

(a) Each Independent Transmission Provider must ensure that the level of planned regional resources for a future year (the last year of the planning horizon) is adequate. Annually, each Independent Transmission Provider must:

(1) Perform an electric energy demand forecast for the last year of the planning horizon;

(2) Apportion the regional resource adequacy requirement for the last year of the planning horizon among the load serving entities in its area on the basis of the ratio of their loads;

(3) Require each load-serving entity in its area to submit to the Independent Transmission Provider a plan (including generation, transmission and demand-side options) to meet the load-serving entity's share of the regional resource adequacy requirement for the last year of the planning horizon; and

(4) Ensure that each load-serving entity's electric energy resource plan meets standards approved by the Commission and is feasible, including ensuring that resources are not double counted by different load serving entities.

(b) This requirement shall replace installed capacity requirements approved by the Commission prior to [effective date of Standard Market Design Rule].

§ 35.38 Long-term transmission planning and expansion.

(a) Each Independent Transmission Provider shall keep on file with the Commission a regional transmission expansion plan.

(b) Each Independent Transmission Provider's regional transmission expansion plan shall, at a minimum:

(1) permit all market participants to participate equally in a facilitated process to identify transmission projects that would best serve the needs of the region; and

(2) require the Independent Transmission Provider to issue requests for proposals to address transmission planning needs identified through such a process.

(c) Independent Transmission Providers shall satisfy the provisions of § 35.34(k)(7) of this title no later than the date on which service commences under Standard Market Design.

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

APPENDICES

A. INTERIM *PRO FORMA* TARIFF REVISIONS
B. STANDARD MARKET DESIGN TARIFF (SMD TARIFF)
C. EXAMPLES OF FLAWS IN THE CURRENT REGULATORY ENVIRONMENT
D. CONVERSION OF THE ORDER NO. 888 *PRO FORMA* TARIFF TO THE REVISED STANDARD MARKET DESIGN *PRO FORMA* TARIFF
E. STANDARD MARKET DESIGN AND TRADING STRATEGIES ENCOUNTERED IN INDEPENDENT SYSTEM OPERATORS
F. ACCESS CHARGES AND CONGESTION REVENUE RIGHTS
G. FORM FOR ANNUAL SELF-CERTIFICATION OF COMPLIANCE WITH FERC SECURITY STANDARDS

Appendix A—Proposed Revisions to Order No. 888—A Pro Forma Open Access Transmission Tariff

Among the revisions that the Commission proposes to require the Transmission Provider to file are revisions to Sections 1.19, 13.5, 13.6, 14.2, 22.1(a), 28.2, 28.3, 33.2, 33.3, 33.5, and 33.7 to recognize that the preferences contained in the tariff for native load customers and for the Transmission Provider's use of its system have been eliminated. The changes are set forth below:

1.19 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. The Transmission Provider will take Network Integration Transmission Service under Part III of the Tariff on their behalf.

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 all customers taking firm 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 more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. 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, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers, including transmission service taken by the Transmission Provider for native load, 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. 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.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of 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.

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.

28.2 Transmission Provider Responsibilities: 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. The Transmission Provider, as a Network Customer, shall be required to designate resources and loads on behalf of its Native Load Customers, 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 transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity 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 all Network Customers for the delivery of capacity and energy from designated Network Resources on a basis that is comparable to the Transmission Provider's historical use of the Transmission System to reliably serve its Native Load Customers.

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.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, all Network Customers, including network service taken by the Transmission Provider on behalf of its Native Load Customers, will bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

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 all Network Customers, including the Transmission Provider on behalf of its Native Load Customers 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.

33.7 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. 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.

In addition, the Commission proposes to require Transmission Providers to make the following changes to section 2 of the pro forma tariff:

2. Reservation Priority for Existing Firm Service Customers

2.1 Right of First Refusal: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year 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 a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. 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 one-year or longer.

2.2 Notice of Rollover: Consistent with requests for new service described in Section 13.2 of Part II of the Tariff, a Transmission Customer must submit its request to exercise rollover rights no later than sixty (60) days prior to the date the current service agreement expires.

2.3 Future Load Growth: The Transmission Provider may reserve existing transmission capacity needed for future load growth reasonably forecasted within the Transmission Provider's current planning horizon. The Transmission Provider may decline a Customer the ability to roll over its firm transmission service with a term of one year or longer only if the Transmission Provider includes in the original service agreement a specific, reasonably forecasted need for the transfer capability to serve load growth at the end of the term of the service agreement.

2.4 Redirects: A Customer receiving firm transmission service with a term of one year or longer which requests to use alternate point(s) of receipt or delivery retains its right of first refusal for service the original point(s) of receipt and delivery at the time the current service agreement expires.

Appendix B—SMD Tariff

Standard Market Design Pro Forma Open Access Transmission Tariff Table of Contents

Part III. Day-Ahead and Real-Time Market Services

Part I. General Term and Conditions

A. Common Service Provisions

1. Definitions

Access Charge: A charge designed to recover the embedded costs of the Transmission System.

Ancillary Services: Those services that are necessary to support the transmission of Energy from Resources to Loads while maintaining reliable operation of the Independent Transmission Provider's Transmission System in accordance with Good Utility Practice.

Automatic Generation Control (''AGC''): The automatic regulation of the power output of electric generating facilities within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

Availability Bid: Bid by a Resource that indicates the minimum price at which Regulation or Operating Reserves is offered to be supplied.

Available Transfer Capability (''ATC''): A measure of the Transfer Capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability, less the sum of existing transmission commitments (including transmission which is used for reliability purposes).

Base Point Signal: Signals sent from the Independent Transmission Provider and ultimately received by Resources specifying the scheduled MW level for the Resource.

Bid: Offer to purchase and/or sell products or services in an Auction, including Energy, Demand Reductions, Transmission Service, Congestion Revenue Rights and/or Ancillary Services at a specified location, quantity, and time-period that is duly submitted to the Independent Transmission Provider pursuant to Independent Transmission Provider Procedures. The Bid should indicate either a specific price or the Bidder's desire to have the Bid accepted regardless of the market clearing price.

Bid Revenue Sufficiency Guarantee: A guarantee by the Independent Transmission Provider that ensures the minimum recovery of the Bid prices for Resources scheduled through the Day-Ahead Market, in subsequent post Day-Ahead Market commitments for reliability, and in the Real-Time Market.

Bilateral Transaction Schedule: Simultaneous schedules of Load and Generation of the same MW level by a Market Participant.

Boundary Interface: Point(s) used to indicate Point(s) of Receipt and Point(s) of Delivery outside of the Service Area.

Commission (''FERC''): The Federal Energy Regulatory Commission, or any successor agency.

Completed Application: An application for Transmission or Market Service that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Congestion: The state of a Transmission System when a binding limit (constraint) on the system's Transfer Capability is reached that must be addressed.

Congestion Charges: Charges relating to the Marginal Congestion Component of Energy Purchases or Transmission Usage Charges. These charges reflect the increased cost that result from dispatching the Transmission System to respect Transmission System (or Flowgate) constraints.

Congestion Revenue Deficit: In the Day-Ahead Market, the absolute value of the difference between the Hourly Congestion Charge Collection and the Hourly Net Congestion Revenue Owed to Congestion Revenue Rights Holders when the difference is negative.

Congestion Revenue Right: A property right held by a Customer that entitles and/or obligates the holder of the right to receive specified Congestion revenues.

Congestion Revenue Surplus: In the Day-Ahead Market, the difference between the Hourly Congestion Charge Collection and the Hourly Net Congestion Revenue Owed to Congestion Revenue Rights Holders when the difference is positive.

Contingency: An actual or potential unexpected failure or outage of a system component, such as a Generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Center: The equipment, facilities and personnel used by the Independent Transmission Provider to coordinate and direct the operation of the Service Area and to administer the Day-Ahead and Real-Time Markets, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the Day-Ahead and Real-Time Markets or the operation of the Service Area.

Curtailment: Reduced transmission service or provision of electricity to a Customer in response to a transmission capability for reliability purposes.

Customer: An entity which has complied with the requirements contained in this Tariff, including having signed a Service Agreement, and is eligible to utilize the services provided by the Independent Transmission Provider under this Tariff; provided, however, that a party taking services under this Tariff pursuant to an unsigned Network Access Service Agreement filed with the Commission by the Independent Transmission Provider shall be deemed a Customer.

Day-Ahead: Nominally, the twenty-four hour period directly preceding the Operating Day, except when this period may be extended by the Independent Transmission Provider to accommodate holidays and weekends.

Day-Ahead Market: The market administered by the Independent Transmission Provider in which Energy, Ancillary Services, and Transmission Services are scheduled and sold Day-Ahead, consistent of the Day-Ahead scheduling process, price calculations, and settlements.

Decremental Energy Bid: A Bid Price curve provided by an entity engaged in a bilateral Import or Internal Transaction to indicate the LMP below which that entity is willing to reduce its Generator's output and purchase Energy in the LMP Markets.

Delivering Party: The entity supplying capacity and Energy to be transmitted at Point(s) of Receipt.

Delivery Point: The location where a transaction terminates. A Delivery Point can be a delivery Node, an aggregation of delivery Nodes, an Interface, or a Trading Hub. For purposes of this Tariff, the Delivery Point does not have to be a location where power is consumed.

Direct Assignment Facilities: Facilities or portions of facilities that are constructed for the sole use/benefit of a particular Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Customer and shall be subject to Commission approval.

Dispatch Hour: The sixty (60) minute period commencing at the beginning of each hour (0000 hour).

Dispatch Interval: Length of time between dispatch instructions from the Independent Transmission Provider.

Emergency: Any abnormal system condition that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of the electric system.

Energy: A quantity of electricity that is Bid, produced, purchased, consumed, sold or transmitted over a period of time and measured or calculated in megawatt-hours.

Energy Bid: For an Energy Supplier, a Bid curve that indicates an entity's willingness to supply Energy at certain prices to markets operated by the Independent Transmission Provider. For an Energy Purchaser, Bid curve that indicates an entity's willingness to purchase Energy at certain prices in markets operated by the Independent Transmission Provider.

Energy Limited Resource: Capacity Resources that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis.

Ex Ante Real-Time Energy LMP: The LMP that is produced by the Independent Transmission Provider's Security Constrained Dispatch and communicated to Resources under dispatch instructions in advance of real time. Under SMD, the LMP used for settlement is the Ex Post LMP.

Ex Post Real-Time Energy LMP: The LMP that is produced following the evaluation of actual dispatch relative to dispatch instructions. It is the LMP used for settlement purposes in the Real-Time Market.

Existing Transmission Contract: A contract for Transmission Service or wholesale requirements service currently in effect between two or more Transmission Owners, or between a Transmission Owner and another entity, that was executed on or before July 9, 1996, or earlier.

Export: Energy that is delivered from the Independent Transmission Provider Service Area Interconnection to another Service Area.

External Transaction: A Bilateral Transaction in which either the Receipt Point or the Delivery Point must be a point at the boundary of the Independent Transmission Provider Service Area. If the Receipt Point is a Boundary Interface, then the External Transaction is an Import. If the Delivery Point is a Boundary Interface, then the External Transaction is an Export.

Facilities Study: An engineering study conducted by the Independent Transmission Provider to determine the required modifications to the Independent 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.

Federal Power Act (''FPA''): The Federal Power Act, as may be amended from time-to-time (See 16 U.S.C. § 796 et seq.)

Fixed Block Resource: A unit that, due to operational characteristics, can only be in one of two states: either turned completely off, or turned on and run at a fixed capacity level.

Flowgate: A transmission facility (such as a transmission line or a transformer or some other component of the electrical network) or group of facilities (*e.g.,* an Interface).

Flowgate Right: A Congestion Revenue Right specified by a portion of the total MW capacity over a particular transmission Flowgate in a specified direction. Flowgate Rights entitle the holder to collect congestion revenues associated with the specified MW flow over the identified Flowgate in the specified direction.

Generation Capacity: The sustained maximum net output of a Generator, measured in megawatts, as demonstrated by the performance of a test or through actual operation as defined in the Independent Transmission Provider Procedures.

Generator: A facility capable of supplying Energy, capacity and/or Ancillary Services that is accessible to the Service Area.

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.

Hourly Economic Maximum Level: The maximum MW level a Resource may operate under normal system conditions.

Hourly Economic Minimum Level: The minimum MW level a Resource may operate under normal system conditions.

Hourly Emergency Maximum Level: The maximum MW level a Resource may operate under Emergency system conditions.

Hourly Emergency Minimum Level: The maximum MW level a Resource may operate under Emergency system conditions.

Hub: A mathematical simplification of a set of buses to emulate a single bus for financial and trading purposes. A Hub is defined by a set of buses that are each associated with a fixed numerical weights such that the sum of weights equal one.

Hub Price: The weighted average of Energy LMP's at the buses that comprise the Hub.

Import: Energy that is delivered to an Independent Transmission Provider Service Area Interconnection from another Service Area.

Incremental Energy Bid: A Bid Price curve for Energy generated above the Hourly Minimum Economic Level.

Independent Transmission Provider: The entity that operates the facilities used for the transmission of Energy in interstate commerce and provides transmission service under the Tariff.

Independent Transmission Provider's Monthly Transmission System Peak: The maximum usage of the Independent Transmission Provider's Transmission System in a calendar month.

Interface: A defined set of transmission facilities (see also Boundary Interface).

Internal Transaction: Bilateral Transactions whose Receipt Point and Delivery Point are both within the Independent Transmission Provider's service territory.

Load: A term that refers to either a consumer of Energy or the amount of Energy (MWh) or demand (MW) consumed.

Load Forecast: Independent forecasts by the Independent Transmission Provider of Load within the Independent Transmission Provider's Service Area used in its scheduling decisions to ensure reliable operation of the system.

Load Ratio Share: The ratio of a Load-Serving Entity's Load to total Load within the Service Area during a specified time period.

Load-Serving Entity: An entity, including a municipal electric system and an electric cooperative, authorized by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, to retail Customers located within the Independent Transmission Provider's Service Area, including an entity that takes service directly from the Independent Transmission Provider to supply its own Load in the Independent Transmission Provider's Service Area.

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.

Locational Marginal Pricing (''LMP''): A pricing methodology under which the price of Energy at each location in the Transmission System is equivalent to the cost to supply or the value to purchase the next increment of Load at that location taking into account the physical aspects of the Transmission System. The term LMP also refers to the price of Energy bought or sold at a specific location.

Lower Regulation Limit: The lowest operating point that the Independent Transmission Provider may dispatch a unit for Regulation under normal operating conditions.

Marginal Congestion Component (''MCC''): Component of Locational Marginal Price and Transmission Usage Charge reflecting the cost of dispatching the Resources available to the Independent Transmission Provider such that transmission constraints are respected.

Marginal Loss Charge Collection: The net amounts charged to purchasers associated with the Marginal Loss Component of the hourly LMPs at the purchasers' buses less the net amounts paid to sellers associated with the Marginal Loss Component of the hourly LMPs at the sellers' buses.

Marginal Losses: The Transmission System Real Power Losses associated with each additional MWh of consumption by Load, or each additional MWh transmitted under a Bilateral Transaction as measured at the Points of Withdrawal.

Marginal Losses Component (''MLC''): The component of LMP at a bus that accounts for the Marginal Losses, as measured between that bus and the Reference Bus.

Market Clearing Price: The price of a product or service determined by the Independent Transmission Provider at a given location and time at which the total amounts offered for sale and purchase are equal.

Market Monitor(ing Unit): Entity required to report directly to the Commission and to the independent governing board of the Independent Transmission Provider the results and recommendations derived from its study of the markets operated by the Independent Transmission Provider.

Market Services: Services provided by the Independent Transmission Provider under the Tariff related to the markets for Energy, capacity and Ancillary Services.

Maximum Curtailment Time: Maximum time (in hours) that a supplier of demand response Resources is willing to respond to Curtailment dispatch instructions.

Maximum Run Time: Maximum length of time (in hours) that a Generator can be reliably expected to operate.

Maximum Shut Down Limit: Maximum number of times a Generator is able to shut down in a 24 period.

Maximum Start-up Limit: Maximum number of times a Generator is able to start-up in a 24 period.

Minimum Curtailment Time: Minimum time (in hours) that a supplier of demand response Resources is willing to respond to Curtailment dispatch instructions.

Minimum Down Time: Minimum length of time (in hours) required for a Generator to begin operations following an outage due to operational constraints.

Minimum Generation Bid: The payment required by a Supplier to operate at the unit's Hourly Economic Minimum.

Minimum Generation Emergency: An Emergency declared by the Independent Transmission Provider in which the Independent Transmission Provider anticipates requesting one or more generating Resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Run Time: Minimum length of time (in hours) required for a Generator to be in operation due to operational constraints.

Network Access Service: Transmission service offered by the Independent Transmission Provider under this Tariff. It offers use of the transmission grid by allowing Customers to: (1) Serve Load with any Resource on the system, (2) access any Interface to import power from a neighboring system, (3) integrate, economically dispatch and regulate its current and planned Resources to serve its Load; (4) transmit power through and out of the Independent Transmission Provider's system, and (5) aggregate Resources for resale and hub-to-hub transfer.

Network Operating Agreement: Agreement that contains the terms and conditions under which the Customer shall operate its facilities and the technical and operational matters associated with the implementation of the Tariff.

Network Operating Committee: Committee responsible for coordinating operating criteria to determine each Party's responsibilities under the Network Operating Agreement.

No-load Cost: Hourly costs associated with generating at a unit's Hourly Economic Minimum.

Node: A location where Energy can be injected and/or withdrawn from the grid.

Normal Response Rate: The expected response rate of an Energy supplying Resource measured in MW/min.

Obligation Right: A Congestion Revenue Right that requires the Customer to receive the Congestion revenues (either positive or negative).

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.

Operable Capacity: Capacity that is readily converted to Energy and is measured in MW.

Operating Day: The daily 24 hour period beginning at midnight for which transactions on the Energy Market are scheduled.

Operating Reserves: Generator Capacity that is available to supply Energy, or Load Resources that are available to Curtail Energy usage, in the event of Contingency conditions, which meet the requirements of the Independent Transmission Provider. Operating Reserves include Spinning Reserves and Supplemental Reserves.

Opportunity Cost: The cost of giving up the opportunity to sell (or consume) a product (or service) at a location and time in order to sell a related product (requiring the same inputs), at the same location and time or the same product at another location and time.

Optimal Power Flow (''OPF''): A Power Flow that maximizes the value (as expressed in the Bids) of the Congestion Revenue Rights, subject to the constraint that the selected set of Bids must be simultaneously feasible.

Option Right: A Congestion Revenue Right that allows the Customer to receive the positive Congestion revenues without the obligation to pay Congestion revenues when they are negative.

Planning Horizon: The number of years ahead in each region for which the Load-Serving Entities must demonstrate to the Independent Transmission Provider that they have procured adequate Energy Resources.

Power Flow: A simulation tool that provides an estimate of Energy flows on the Transmission System and adjacent transmission systems under a given set of assumed characteristics.

Primary Holder: The Owner of a Congestion Revenue Right recognized as such by the Independent Transmission Provider for settlement purposes.

Real Power Losses: The loss of Energy, resulting from transporting power over the Transmission System, between the Point of Injection and Point of Withdrawal of that Energy.

Real Time: Referring to the time period in which transmission and generation dispatch instructions are ultimately given.

Real-Time Market: The market administered by the Independent Transmission Provider for Energy, Ancillary Services, and Transmission Services in real time, consisting of the real time scheduling process, dispatch, price calculations, and settlements.

Receipt Point: The location where a Transaction originates. A Receipt Point can be a Generator Node, an aggregation of Generator Nodes, an Interface, or a Trading Hub. For purposes of this Tariff, a Receipt Point does not have to be a Generator.

Receipt Point-to-Delivery Point Congestion Revenue Right Obligation: Congestion Revenue Rights that confer: (i) The right to collect revenues equal to the applicable Marginal Congestion Component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is positive, and (ii) the obligation to pay an amount to the Independent Transmission Provider equal to the absolute value of the applicable Marginal Congestion Component of the hourly Transmission Usage Charge when the Marginal Congestion Component is negative.

Receipt Point-to-Delivery Point Congestion Revenue Right Option: Congestion Revenue Rights that confer to the holder the right to collect revenues equal to the applicable Congestion Charge component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is positive, but do not obligate the holder to pay the absolute value of the applicable Marginal Congestion Component of the hourly Transmission Usage Charge when the Marginal Congestion Component is negative.

Receiving Party: The entity receiving the capacity and Energy transmitted by the Independent Transmission Provider to Point(s) of Delivery.

Reference Bus: The location on the Transmission System relative to which all mathematical quantities, including Shift Factors and penalty factors relating to physical operation, will be calculated.

Regulation: The capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the Manuals. Regulation also encompasses regulation and frequency response service i.e. the continuous balancing of Resources (generation and interchange) with Load variations in order to maintain scheduled Interconnection frequency.

Regulation Capability: The maximum amount of Regulation Service in MW a Resource can operationally provide to the Independent Transmission Provider.

Regulation Requirement: Quantity of Regulation identified by the local reliability authority to be procured by the Independent Transmission Provider to ensure system reliability.

Reliability Rules: Those rules, standards, procedures and protocols, including Local Reliability Rules, developed in accordance with NERC, regional reliability councils, FERC, PSC and NRC standards, rules and regulations, and other criteria.

Reserve Location: Geographic area for which there is a specific Operating Reserve requirement applies.

Resource: Either a Generator or a Load that can reliably adjust its electricity usage by some specified range and rate at a specific Withdrawal Point in response to Day-Ahead or Real-Time prices or by instruction by the Independent Transmission Provider.

Resource Adequacy Requirement: The Resource reserve margin, stated as a ratio of the reserves to the forecast peak load during the final year of the Planning Horizon, expressed as a percentage.

Response Rate: The capability (in MW/minute) of a Resource to adjust its generation level in response to dispatch signals.

Scheduled Amount: Megawatt supply or demand obligation as indicated by the Independent Transmission Provider's Schedule.

Scheduled Resource: Resource incurring a supply or demand obligation as indicated by the Independent Transmission Provider's Schedule.

Security Constrained Dispatch: The determination of the dispatch that incorporates all transmission constraints necessary for reliability.

Security Constrained Unit Commitment: The allocation of Load to Generators by the Independent Transmission Provider through the operation of a computer algorithm which continuously calculates individual Generator loading at minimum Bid cost, balancing Load and scheduled interchange with generation while meeting all reliability rules and Generator performance constraints.

Self-Schedule: The Supplier's provision to the Independent Transmission Provider with its hourly Energy schedule in the Day-Ahead Market and Real-Time Market independent of market prices.

Self-Supply: The provision of certain Ancillary Services, or the provision of Energy to replace Marginal Losses, by a Customer using either the Customer's own Generators or generation obtained from an entity other than the Independent Transmission Provider.

Seller: Market Participant whose Bid to supply into either the Day-Ahead or Real-Time Market has been accepted and who has incurred the associated supply obligations.

Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Customer and the Independent Transmission Provider for service under the Tariff.

Service Area: The geographic region and transmission facilities therein that are under the operational control of the Independent Transmission Provider.

Service Commencement Date: The date the Independent Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Independent Transmission Provider begins to provide service in accordance with the Tariff.

Settlement: The process of determining the charges to be paid to or by a Customer in the markets operated by the Independent Transmission Provider under this Tariff.

Shift Factor: A ratio, calculated by the Independent Transmission Provider, that compares (1) the change in power flow through a transmission facility resulting from an incremental change in injection of power at a Receipt Point and withdrawal of power at the Delivery Point to (2) the incremental change in injection of power at the Receipt Point.

Shortage: A situation in which the markets for Energy, Regulation or Operating Reserves are not able to clear because of insufficient Bid-in capacity.

Spinning Reserves: Operating Reserves provided by synchronized Resources that can respond immediately to dispatch instructions.

Spinning Reserves Requirement: Quantity of Spinning Reserves identified by the local reliability authority to be procured by the Independent Transmission Provider to ensure system reliability.

Start Time: The number of hours required by a generating Resource to reach its Hourly Economic Minimum Level.

Start-up Cost: Payment needed by the Purchaser of Energy to cover the fixed costs associated with its Energy Bid or payment required by Generator to Start-up and reach its minimum operating level.

Supplemental Commitment: Scheduling of Resources by the Independent Transmission Provider following the posting of the Day-Ahead Schedule to meet the reliability needs.

Supplemental Reserves: Operating Reserves provided by Resources that can be started, synchronized and loaded within a specified time period.

Supplemental Reserves Requirement: Quantity of Supplemental Reserves identified by the local reliability authority to be procured by the Independent Transmission Provider to ensure system reliability.

Supplier: A Party that is supplying the Demand Reduction, Energy and/or associated Ancillary Services to be made available under the Tariff, including Generators and demand side Resources that satisfy all applicable Independent Transmission Provider requirements.

System Impact Study: An assessment by the Independent Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for Congestion Revenue Rights or (ii) whether any additional costs may be incurred in order to provide Congestion Revenue Rights.

System Marginal Price (SMP): The LMP of Energy at the Reference Bus.

Total Transfer Capability: The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner.

Transaction: The purchase and/or sale of Energy, Congestion Revenue Rights, Ancillary Services, or Transmission Service.

Transfer Capability: The measure of the ability of interconnected electrical systems to reliably move or transfer power from a set of Receipt Points to a set of Delivery Points over all transmission facilities (or paths) between those areas under specified system conditions.

Transmission Owner: Entity with financial ownership of the transmission assets used in the provision of Transmission Service by the Independent Transmission Provider.

Transmission Owner's Monthly Transmission System Peak: The maximum hourly firm usage as measured in megawatts (MW) of the Transmission Owner's transmission system in a calendar month.

Transmission Planned Outage: Any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified by the Independent Transmission Provider.

Transmission Service: Services needed to move Energy from a Receipt Point to a Delivery Point provided to Customers by the Independent Transmission Provider in accordance with this Tariff.

Transmission System: The facilities controlled and operated by the Independent

Transmission Provider that are used to provide transmission service under the Tariff.

Transmission Usage Charge: A per unit charge for Transmission Service to support a Bilateral Transaction. The Transmission Usage Charge is equal to the difference of the LMP at the Delivery Point and the LMP at the Receipt Point (in $/MWh).

Unit-Specific Opportunity Cost: The Opportunity Cost calculation for specific Resources that are selected to provide Regulation or Operating Reserves in either the Day-Ahead or the Real-Time Markets.

Upper Regulation Limit: The highest operating point that the Independent Transmission Provider will dispatch a unit for Regulation under normal operating conditions.

Virtual Demand Bid: A Demand Bid in the Day-Ahead Market without a physical Resource capable of withdrawing Energy in the Real-Time Market.

Virtual Energy: Energy purchased or sold in the Day-Ahead Energy Market that is not backed by physical Resources.

Virtual Supply Bid: A Supply Bid in the Day-Ahead Market without a physical Resource capable of injecting Energy in the Real-Time Market.

Voltage Support Service: The provision of reactive power support necessary to maintain transmission voltage.

Wheel Through: Transmission Service through the Service Area of the Independent Transmission Provider that originates and terminates outside the Service Area of the Independent Transmission Provider.

Zonal-LMP: Load weighted average of Energy LMPs over a set of buses and weights defined by a zone.

Zone: A set of buses in a geographic area.

Zone Price: Load weighted average price over the defined set of buses in a zone.

2. 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 § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities).

3. Local Furnishing Bonds

3.1 Transmission Owners That Own Facilities Financed by Local Furnishing Bonds: This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of Energy with tax-exempt bonds, as described in section 142(f) of the Internal Revenue Code of 1986, as amended, or corresponding provisions of predecessor statutes (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Independent Transmission Provider shall not be required to provide transmission service to any 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, in whole or in part, to finance the Transmission Owner's facilities, regardless of whether such facilities financed with these bonds are transmission, distribution, or generation facilities.

3.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Independent Transmission Provider determines that the provision of transmission service requested by a Customer would jeopardize the tax-exempt status of any outstanding local furnishing bond(s) used, in whole or part, to finance any of the Transmission Owner's facilities, regardless of whether such facilities financed with these bonds are transmission, distribution, or generation facilities, or would jeopardize the Transmission Owner's entitlement to income tax deductions for interest expense in connection with such tax-exempt bonds, it shall advise the Customer within thirty (30) days of receipt of the Completed Application of (a) such determination and (b) the reasonably expected amount of any costs resulting from such loss of tax-exempt status and/or income tax deductions (or from the prevention of any such loss). For purposes of this section, the costs resulting from such loss of tax exempt status and/or income tax deductions (or from the prevention of any such loss) due to the provision of such transmission service shall include, without limitation, any reasonable transactions costs (including any redemption premium) of defeasing and/or redeeming any outstanding local furnishing bonds and/or from any such refinancing with taxable debt and/or from any disallowance or loss of a deduction for tax purposes of the interest in respect of such bonds.

(ii) If the 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 Independent 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 Independent 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 specifying that such service is provided subject to the Customer's payment of all costs deemed by the Commission to be eligible for recovery under Section 212(a) of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Independent Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff and such order. Transmission service shall not commence until after the Customer complies with the creditworthiness provisions of Section 8 of this Tariff.

4. Reciprocity

A Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing on similar terms and conditions over facilities used for the transmission of Energy owned, controlled or operated by the Customer and over facilities used for the transmission of Energy owned, controlled or operated by the Customer's corporate affiliates. A Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of Energy owned, controlled or operated by the Customer and over facilities used for the transmission of Energy owned, controlled or operated by the Customer's corporate affiliates.

This reciprocity requirement applies not only to the 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 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 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 a Customer to avoid the requirements of this provision.

5. Billing and Payment

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

5.2 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 Independent Transmission Provider.

5.3 Customer Default: In the event the Customer fails, for any reason other than a billing dispute as described below, to make payment to the Independent 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 Independent Transmission Provider notifies the Customer to cure such failure, a default by the Customer shall be deemed to exist. Upon the occurrence of a default, the Independent 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 Independent Transmission Provider and the Customer, the Independent Transmission Provider will continue to provide service under the Service Agreement as long as the 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 Customer fails to meet these two requirements for continuation of service, then the Independent Transmission Provider may provide notice to the Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

6. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the jurisdictional Independent 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.

7. Force Majeure and Indemnification

7.1 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 Independent Transmission Provider nor the 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.

7.2 Indemnification: The Customer shall at all times indemnify, defend, and save the Independent 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 Independent Transmission Provider's performance of its obligations under this Tariff on behalf of the Customer, except in cases of negligence or intentional wrongdoing by the Independent Transmission Provider.

8. Creditworthiness

For the purpose of determining the ability of the Customer to meet its obligations related to service hereunder, the Independent Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Independent Transmission Provider may require the 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 Customer and acceptable to the Independent Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Independent Transmission Provider against the risk of non-payment.

9. Eligibility for Independent Transmission Provider Services

In order to purchase Network Access Service, purchase or supply Energy, or to supply Ancillary Services in the Independent Transmission Provider Administered Markets, Customers must satisfy the requirements of this Article.

9.1 Requirements for Network Access Service: A Customer eligible for Network Access Service is: (i) any electric utility (including the Load-Serving Entity or any power marketer), Federal power marketing agency, or any person generating Energy for sale is eligible to be a Customer for Network Access Service under the Tariff. Energy sold or produced by such entity may be 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 Independent Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Independent Transmission Provider. (ii) Any retail Customer taking unbundled transmission service pursuant to a state requirement that the Independent Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Independent Transmission Provider, is eligible to be a Customer under the Tariff.

9.2 Requirements for Market Services: The Independent Transmission Provider and each market participant shall execute a Service Agreement for Market Services which sets forth the terms and conditions under which a market participant shall either supply or purchase market services, consistent with the Form of Service Agreement for Market Services in Part VII.

9.3 Participating Generator Agreements: The Independent Transmission Provider and the owners of each Generator shall enter into a Participating Generator Agreement which shall be filed with the Commission. Each Participating Generator Agreement shall set forth the operating terms, conditions, and obligations concerning the dispatch of a generating unit.

9.4 Requirements Common to All Customers: Completed Application and Minimum Technical Requirements

A Customer shall submit a Completed Application and shall receive Independent Transmission Provider approval prior to obtaining any services under the Independent Transmission Provider's Tariff. A Customer also shall demonstrate to the Independent Transmission Provider's reasonable satisfaction that it is capable of performing all functions required by the Independent Transmission Provider's Tariff including operational, financial and settlement requirements.

9.4.1 Application: Each Customer requesting to schedule, take or provide any services under the Tariff must apply to the Independent Transmission Provider in writing at least sixty (60) days in advance of the month in which service is to commence. The Independent Transmission Provider will consider requests for such services on shorter notice when feasible. Service commencement will depend on the Independent Transmission Provider's ability to accommodate the request. To apply, the Customer shall complete and deliver a Service Agreement (in the form of Part VII) and an Application to the Independent Transmission Provider.

9.4.2 Completed Application: A Completed Application shall provide all of the information reasonably required by the Independent Transmission Provider to permit the Independent Transmission Provider to perform its responsibilities under the Independent Transmission Provider's Tariff. A Customer taking or providing service under the Tariff shall provide the Independent Transmission Provider, upon application for service, with a list identifying its parent company as well as any affiliate. The Customer shall notify the Independent Transmission Provider within 30 days of the effective date of any change to the original list. Any Customer shall notify the Independent Transmission Provider within 30 days of the effective date of any change to the original list. Any Customer shall respond within 10 days to a request by the Independent Transmission Provider to update the list of affiliates and/or parent company. The Independent Transmission Provider shall treat the information provided in the Application as Confidential Information except to the extent that disclosure of the information is required by the Independent Transmission Provider's Tariff, by regulatory or judicial order or for reliability purposes pursuant to Good Utility Practice.

9.4.3 Approval of Application and/or Notice of Deficient Application:

The Independent Transmission Provider will promptly review the Application and may request additional information to determine whether the applicant meets the Independent Transmission Provider's minimum financial and technical requirements. The Independent Transmission Provider will notify the applicant within thirty (30) days of receipt of a Completed Application.

If the Independent Transmission Provider rejects an Application, the Independent Transmission Provider shall provide a written explanation within fourteen (14) days of the rejection. The Independent Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the applicant. If such efforts are unsuccessful, the Independent Transmission Provider shall return the Application.

10. Dispute Resolution Procedures

10.1 Internal Dispute Resolution Procedures: Any dispute between a Customer and the Independent Transmission Provider involving transmission or Market Services 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 Independent Transmission Provider and a senior representative of the 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.

10.2 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.

10.3 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.

10.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) 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

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

10.5 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.

11. Metering

11.1 Customer Requirements: The Independent Transmission Provider shall establish metering specifications and standards for all metering that is used as a data source by the Independent Transmission Provider. Customers shall install and maintain such metering at their own expense and deliver data to the Independent Transmission Provider without charge. A Customer taking service under the Independent Transmission Provider's Tariff will make available to the Independent Transmission Provider metered data that meets Independent Transmission Provider requirements by one of the following means: (i) Direct transmission to the Independent Transmission Provider; (ii) direct transmission to the Independent Transmission Provider through Transmission Owner communications equipment, or (iii) indirectly through metering provided by the Transmission Owner within whose area its Load is located. The Customer also shall provide its metered data to the Transmission Owner within whose area its Load is located, to the extent that the Transmission Owner determines that the metered data provided to the Independent Transmission Provider is required for its system operation and planning functions, for the billing of services it provides to the Customer, or to perform calculations required by the Independent Transmission Provider.

11.2 Load-Serving Entities: Any Load that is not directly metered, as described above, will have its Load determined by the Transmission Owner within whose area its Load is located in accordance with the Transmission Owner's Retail Access plan on file with the (state commission) or otherwise authorized.

11.3 Ancillary Service Suppliers: Suppliers shall ensure that adequate metering data is made available to the Independent Transmission Provider as described above.

11.4 Third Party Metering Services: Customers whose metering services are provided by third parties qualified under rules, regulations and procedures of applicable state regulatory authorities shall be responsible to ensure that all data described in this Section are satisfactorily made available to the Independent Transmission Provider and applicable Transmission Owner(s) by those third parties.

11.5 Estimation of Metering: In the event of a meter malfunction or inadequate metering data, the Independent Transmission Provider may use estimates to determine Customer's rights and responsibilities under the Independent Transmission Provider's Tariff.

12. Data and Confidentiality Provisions

12.1 Access to Complete and Accurate Data: Customers under the Tariff shall provide to the Independent Transmission Provider such information and data as the Independent Transmission Provider reasonably deems necessary in order to perform its functions and fulfill its responsibilities under the Tariff and in accordance with the Independent Transmission Provider Market Monitoring Program. Such information will be provided on a timely basis and in the formats prescribed in the Independent Transmission Provider Procedures.

12.2 Independent Transmission Provider Procedures: The Independent Transmission Provider shall develop, and modify as appropriate, procedures for the efficient and non-discriminatory operation of the Independent Transmission Provider Administered Markets and for the safe and reliable operation of the Independent Transmission Provider's Service Area in accordance with the terms and conditions of the Tariff. All such procedures must be consistent with Good Utility Practice. Whenever requested by the Independent Transmission Provider, each Load-Serving Entity shall provide the Independent Transmission Provider with a forecast of the Loads for which it is responsible for the particular time period designated by the Independent Transmission Provider. Customers shall inform the Independent Transmission Provider of the Availability of Generators within the Independent Transmission Provider Service Area subject to a Customer's control by Energy contract, ownership or otherwise. Additionally, the Transmission Owners will provide megawatt, megavar, voltage readings, Transmission System data (facility ratings and impedance data), and maintenance schedules for all Transmission Facilities under the Independent Transmission Provider's Operational Control. For Transmission Facilities Requiring Independent Transmission Provider Notification, the Transmission Owners shall inform the Independent Transmission Provider of all changes in the status of the designated transmission facilities. Suppliers will provide data on Generator status and output including maintenance schedules, Generator scheduled return dates (inclusive of return to service from maintenance, forced outages or partial unit outages that resulted in a significant reduction in a generating unit's ability to produce Energy in any hour), and Generator machine data. These data shall also include Generator Incremental/Decremental Bids, operating limits, response rates, megawatt, megavar, and voltage readings.

12.3 Access to Confidential Information: The Independent Transmission Provider may request, and the Customer shall provide, Confidential Information consistent with the disclosure requirements set forth in the Independent Transmission Provider's Tariff. The Independent Transmission Provider shall prevent the disclosure of Confidential Information and shall not publish, disclose or otherwise divulge Confidential Information to any person or entity without the prior written consent of the party supplying such Confidential Information, except as provided for under the Independent Transmission Provider Market Power Monitoring Plan. The provisions of this Section shall not apply to any Confidential Information: (i) Which was in the public domain at the time of disclosure hereunder; (ii) which thereafter passes into the public domain by acts other than the acts of the Independent Transmission Provider; (iii) that the Independent Transmission Provider is required to make publicly available by the Commission, the (state commission) or other legal process, or for reliability purposes pursuant to Good Utility Practice; or (iv) information required to be provided to the Commission, which will be protected under the Commission's rules for non-public material. A Customer may request that the Independent Transmission Provider keep confidential from another entity Confidential Information that the other entity does not require to perform its obligations and duties hereunder. The Customer must state in writing that the information is to be treated as Confidential Information and the reasons for treating it as Confidential Information, otherwise information will be treated as non-Confidential Information.

12.4 Use of Confidential Information: The Independent Transmission Provider shall use Confidential Information for the exclusive purpose of performing its obligations hereunder and under any Service Agreement.

12.5 Disclosure of Bid Information: Pursuant to Commission requirements, the Independent Transmission Provider shall make public Bid information from the Energy, Ancillary Services, and Transmission markets (but not the names of the Bidders making these Bids) three months after the Bids are submitted. The Independent Transmission Provider shall post the data in a way that permits third parties to track each individual Bidder's Bids over time. Prior to such disclosure, Bid information submitted to the Independent Transmission Provider by Market Participants shall be considered Confidential Information.

12.6 Survival: This section 12 will survive the termination of the Independent Transmission Provider's Tariff and any associated Service Agreement.

Part II. Transmission Services

B. Network Access Service

Preamble

The Independent Transmission Provider will provide Network Access Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Access Service allows all Customers to access all points (*i.e.*, all Receipt Points and all Delivery Points on the Independent Transmission Provider's system) so that every Generator can reach every Load, subject to physical feasibility. Specifically, Network Access Service offers a flexible use of the transmission grid by allowing Customers to: (1) Serve Load with any Resource on the system, (2) access any Interface to import power from a neighboring system, (3) integrate, economically dispatch and regulate its current and planned Resources to serve its Load; (4) transmit power within, through, and out of the Independent Transmission Provider's system; and (5) aggregate Resources for resale and hub-to-hub transfer.

1. Nature of Network Access Service

1.1 Scope of Service: Network Access Service allows all Customers to access all points (*i.e.*, all Receipt Point and Delivery Points) on the Independent Transmission Provider's system so that every Customer can move power from any Generator to any Load, from any Generator to any Trading Hub, from one Trading Hub to another, or from a Trading Hub to a Load. Using Network Access Service, a Customer can integrate Resources and Load, transfer power through or out of the Independent Transmission Provider's system or deliver power between specified Receipt and Delivery Points. The embedded costs of the Transmission System will be recovered through an Access Charge. Any Congestion costs and loss costs associated with a transaction will be recovered through the applicable Transmission Usage Charge in which the Customer causing the Congestion and losses bears the full cost of its Transaction. To the extent the Customer is willing to pay the applicable Transmission Usage Charge for its requested Receipt Point-to-Delivery Point combinations(s), service will be available and will be provided to the extent physically and operationally feasible. The Customer must obtain or self-supply Ancillary Services pursuant to Part II.C of the Tariff.

1.2 Independent Transmission Provider Responsibilities: The Independent Transmission Provider shall plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide all Customers with Network Access Service over the Independent Transmission Provider's Transmission System. The Independent Transmission Provider shall endeavor to have constructed and placed into service sufficient transmission capability to deliver all Network Access Service Customers' Resources to serve Load. The Independent Transmission Provider will offer a mechanism for participants to identify long-term planning and expansion needs and to propose solutions (transmission, generation, or demand-side).

1.3 Service at Points without Concurrent Congestion Revenue Rights: Once a Customer agrees to pay the applicable Access Charge, it may use the Independent Transmission Provider's Transmission System to deliver Energy to its Network Loads from Resources when the Customer does not have Congestion Revenue Rights between the requested Receipt and Delivery Points. Such Energy shall be transmitted subject to the Customer paying the applicable Transmission Usage Charge. A Customer may revise or add Receipt Points or Delivery Points without an additional Access Charge.

2. Initiating Service

2.1 Condition Precedent for Receiving Service: A request for Network Access Service may be performed under an umbrella Service Agreement pursuant to Part VII of the Tariff. A request for Network Access Service must contain a written Application to: [the Independent Transmission Provider Name and Address], submitted at least sixty (60) days in advance of the calendar month in which service is to commence. The Independent Transmission Provider will consider requests for such service on shorter notice when feasible. Requests for Network Access 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 B.2.8.

2.2 Application Procedures: A Customer requesting Network Access Service must submit an Application, with a deposit approximating the charge for one month of service, to the Independent Transmission Provider as far as possible in advance of the month in which service is to commence. Applications should be submitted by entering the information listed below on the Independent Transmission Provider's OASIS, which will provide a time-stamped record for the Application.

2.2.1 Applications That Do Not Require the Integration of Resources and Load: 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 meets, or will be upon commencement of service, will meet the eligibility requirement under Part I of this Tariff;

(iii) The location of the specific Receipt Points and Delivery Points 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 Independent Transmission Provider shall 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 transmission information sharing agreements. The Independent 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; an estimate of the capacity and Energy expected to be delivered to the Receiving Party; and the transmission transfer capability requested for each Receipt Point and Delivery Point on the Independent Transmission Provider's Transmission System; Customers may combine their requests for service in order to satisfy the minimum transmission capability requirement; and

(vi) Service Commencement Date and the term of the requested Network Access Service: The minimum term for Network Access Service is one hour.

2.2.2 Applications That Require the Integration of Resources and Load: 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 meets, or upon commencement of service will meet, the eligibility requirement under Part I of this Tariff;

(iii) A description of the Load at each Delivery Point. This description must separately identify and provide the Customer's best estimate of the total Loads to be served at each transmission voltage level, and the Loads to be served from each Independent Transmission Provider substation at the same transmission voltage level. The description must include a ten (10) year forecast of service for summer and winter Load and Resource requirements beginning with the first year after the service is scheduled to commence and extending for the duration of the service request;

(iv) The amount and location of any demand responsive Loads included in the Network Load. This shall include the summer and winter capacity requirements for each demand responsive Load, that portion of the Load subject to demand response, the conditions under which a response can be implemented and any limitations on the amount and frequency of demand response. Customer should identify the amount of demand responsive Load (if any) included in the ten (10) year Load forecast provided in response to (iii) above.

(v) A description of Network Resources (current and term of request projection), which shall include, for each Network Resource:

—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 Independent Transmission Provider's Service Area, where only a portion of unit output is designated as a Network Resource
—Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and Delivery Point(s) to the Independent Transmission Provider's Transmission System;

(vi) A description of Customer's Transmission System, if applicable:

—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 Independent Transmission Provider
—Operating restrictions needed for reliability
—Operating guides employed by system operators
—Contractual restrictions or committed uses of the Customer's Transmission System, other than the Customer's Network Loads and Resources
—Location of Network Resources described in subsection (v) above
—Ten (10) year projection of system expansions or upgrades
—Transmission System maps that include any proposed expansions or upgrades; and

(vii) Service Commencement Date and the term of the requested Network Access Service: The minimum term for Network Access Service is one hour.

The Independent Transmission Provider shall acknowledge the Completed Application within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Customer. If an Application fails to meet the requirements of this section, the Independent Transmission Provider shall notify the Customer filing the Application requesting service or Congestion Revenue Rights within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Independent Transmission Provider shall attempt to remedy deficiencies in the Application through informal communications with the Customer. If such efforts are unsuccessful, the Independent Transmission Provider shall return the Application without prejudice to the Customer filing a new or revised Application that fully complies with the requirements of this section. The Customer will be assigned a new priority consistent with the date of the new or revised Application. The Independent Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

2.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Access Service shall not commence until the Independent Transmission Provider and the 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 Independent Transmission Provider shall exercise reasonable efforts, in coordination with the Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

2.4 Customer Facilities: To the extent Customer owns transmission facilities, the provision of Network Access Service shall be conditioned upon the 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 Independent Transmission Provider's Transmission System to the Customer. The Customer shall be solely responsible for constructing or installing all facilities on the Customer's side of each such Delivery Point or interconnection.

2.5 Filing of Service Agreement: The Independent Transmission Provider must file Service Agreements or related agreements with the Commission to the extent required by applicable Commission regulations.

2.6 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Independent Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Independent Transmission Provider shall attempt to remedy minor deficiencies in the Application through informal communications with the Customer. If such efforts are unsuccessful, the Independent 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 the Tariff, the Customer shall be assigned a new priority consistent with the date of the new or revised Application.

2.7 Response to a Completed Application: Following receipt of a Completed Application for Network Access Service, the Independent Transmission Provider shall make a determination of physical feasibility as required in Section B.5.2. The Independent Transmission Provider shall notify the 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 offer Network Access 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 B.5.3. Responses by the Independent Transmission Provider must be made as soon as practicable to all Completed Applications and the timing of such responses must be made on a non-discriminatory basis.

2.8 Execution of Service Agreement: Whenever the Independent Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the 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 B.2.5 will govern the execution of a Service Agreement. Failure of a Customer to execute and return the Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section B.2.9 within fifteen (15) days after it is tendered by the Independent 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 a Customer to file another Application after such withdrawal and termination.

2.9 Initiating Service in the Absence of an Executed Service Agreement: If the Independent Transmission Provider and the Customer requesting Network Access Service cannot agree on all the terms and conditions of the Service Agreement, the Independent Transmission Provider shall file with the Commission, within thirty (30) days after the date the Customer provides written notification directing the Independent Transmission Provider to file, an unexecuted Network Access Service Agreement containing terms and conditions deemed appropriate by the Independent Transmission Provider for such requested Transmission Service. The Independent Transmission Provider shall commence providing Transmission Service subject to the Customer agreeing to (i) compensate the Independent Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Tariff including posting appropriate security deposits in accordance with the terms of Section B.2.2.

2.10 Scheduling of Network Access Service: Under Network Access Service, a Customer can schedule transmission service or procure Energy through the Day-Ahead and Real-Time Markets. The scheduling procedures for both options are contained in Part III of this Tariff.

3. Network Resources

To the extent a Customer desires the Independent Transmission Provider to integrate, economically dispatch, and regulate the Customer's Resources to serve the Customer's Load, the Customer must designate Resources as described below. All other Customers will identify Receipt Points and Delivery Points through the Day-Ahead and Real-Time Markets pursuant to Part III of this Tariff.

3.1 Designation of Network Resources: All Customers desiring the Independent Transmission Provider to integrate, economically dispatch, and regulate its Resources to serve its load must designate sufficient Network Resources to meets its Load on a non-interruptible basis. Network Resources shall include all generation owned, purchased or leased by the 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 Customer's Network Load on a non-interruptible basis. Any owned or purchased Resources that were serving the Customer's Loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Customer terminates the designation of such Resources.

3.2 Designation of New Network Resources: The Customer may designate a new Resource by providing the Independent Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made by a request for modification of service pursuant to an Application under Section B.2.

3.3 Designation of Alternate Resources: The Customer has the right to obtain alternate Resources, whether through a bilateral contract or through the Independent Transmission Provider-Administered Markets. Alternate Resources enable the Customer to substitute one Resource for another, generally on a short-term basis. An alternate Resource does not have to be committed to the Customer on a firm basis as does a Network Resource.

3.4 Substitution of Resources and Congestion Revenue Rights: The Customer may replace one designated Resource with another. The Customer may request a reconfiguration of the Congestion Revenue Rights it holds for the current Resource and request Congestion Revenue Rights for the new Resource pursuant to B.6 of the Tariff.

3.5 Termination of Network Resources: The Customer may terminate the designation of all or part of a generating Resource as a Network Resource at any time, but must provide notification to the Independent Transmission Provider as soon as reasonably practicable.

3.6 Customer Dispatch Obligation: As a condition to receiving Network Access Service, the Customer agrees to dispatch its Network Resources as requested by the Independent Transmission Provider, consistent with Part II of this Tariff. To the extent practicable, the redispatch of Resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Customers.

3.7 Transmission Arrangements for Network Resources Not Physically Interconnected with the Independent Transmission Provider: The Customer shall be responsible for any arrangements necessary to deliver capacity and Energy from a Network Resource not physically interconnected with the Independent Transmission Provider's Transmission System. The Independent Transmission Provider will undertake reasonable efforts to assist the Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

3.8 Limitation on Designation of Network Resources: The 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 Customer may establish that execution of a contract is contingent upon the availability of transmission service under the Tariff.

3.9 Customer Owned Transmission Facilities: The Customer that owns existing facilities that are determined by the Order No. 888 seven factor test to be Transmission Facilities may be eligible to receive consideration either through a billing credit or some other mechanism.

4. Designation of Network Load

To the extent a Customer desires the Independent Transmission Provider to integrate, economically dispatch, and regulate the Customer's Resources to serve the Customer's Load, the Customer must designate Loads as described below.

4.1 Network Load: The Customer must designate the individual Network Loads on whose behalf the Independent Transmission Provider will provide Network Access Service. The Network Loads shall be specified in the Service Agreement and shall include actual deliveries at Interfaces.

4.2 New Network Loads Connected with the Independent Transmission Provider: The Customer shall provide the Independent 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 Independent Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section B.5.12 and shall be charged to the Customer in accordance with Part VIII of this Tariff.

4.3 New Interconnection Points: To the extent the Customer desires to add a new Delivery Point or interconnection point between the Independent Transmission Provider's Transmission System and a Network Load, the Customer shall provide the Independent Transmission Provider with as much advance notice as reasonably practicable.

4.4 Changes in Service Requests: Under no circumstances shall the Customer's decision to cancel or delay a requested change in Network Access Service (*e.g.*, the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Customer of its obligation to pay the costs of transmission facilities constructed by the Independent Transmission Provider and charged to the Customer as reflected in the Service Agreement. However, the Independent Transmission Provider must treat any requested change in Network Access Service in a non-discriminatory manner.

4.5 Annual Load and Resource Information Updates: The Customer shall provide the Independent Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Access Service under the Tariff. The Customer also shall provide the Independent Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Customer's Network Load, Network Resources, Transmission System or other aspects of its facilities or operations affecting the Independent Transmission Provider's ability to provide reliable service.

5. Service Availability

5.1 General Conditions: The Independent Transmission Provider shall provide Network Access Service over, on or across its Transmission System to any Customer that has met the requirements of Section A.9.

5.2 Determination of Available Transfer Capability: A description of the Independent Transmission Provider's specific methodology for assessing Available Transfer Capability posted on the Independent Transmission Provider's OASIS is contained in Attachment A of the Tariff. In the event sufficient transmission capability may not exist to accommodate a Congestion Revenue Rights request, the Independent Transmission Provider shall respond by performing a System Impact Study.

5.3 Notice of Need for System Impact Study: After receiving a request for Congestion Revenue Rights or for the reconfiguration of Congestion Revenue Rights, the Independent Transmission Provider shall conduct, to the extent necessary, a System Impact Study. A description of the Independent Transmission Provider's methodology for completing a System Impact Study is provided in Attachment B. The Independent Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Customer shall agree to reimburse the Independent Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Customer shall execute the System Impact Study Agreement and return it to the Independent Transmission Provider within fifteen (15) days. If the Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

5.4 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement must clearly specify the Independent 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 Independent Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Customer will not be assessed a charge for such existing studies; however, the Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Customer's request for service on the Transmission System.

(ii) If in response to multiple Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Independent Transmission Provider to accommodate the service requests, the costs of that study shall be prorated among the Customers.

5.5 System Impact Study Procedures: Upon receipt of an executed System Impact Study, the Independent Transmission Provider shall use due diligence to complete the required System Impact Study within sixty (60) days. The System Impact Study shall identify any system constraints and dispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Independent Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the 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 Customer. The Independent Transmission Provider shall notify the 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, all or part of a request for Congestion Revenue Rights reconfiguration, or if 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 Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

5.6 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Customer's service request, Congestion Revenue Rights Request, or Congestion Revenue Rights Reconfiguration request, the Independent Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Customer a Facilities Study Agreement pursuant to which the Customer shall agree to reimburse the Independent Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Customer shall execute the Facilities Study Agreement and return it to the Independent Transmission Provider within fifteen (15) days. If the 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 Independent Transmission Provider will use due diligence to complete the required Facilities Study within sixty (60) days. If the Independent Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Independent Transmission Provider shall notify the 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 shall include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Customer, (ii) the 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 Customer shall provide the Independent Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Independent Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The 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.

5.7 Facilities Study Modifications: Any change in design arising from an 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 Independent Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Customer pursuant to the provisions of Part II of the Tariff.

5.8 Due Diligence in Completing New Facilities: The Independent Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Independent Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Transmission Service or Congestion Revenue Rights if doing so would impair system reliability or otherwise impair or degrade existing service or Congestion Revenue Rights.

5.9 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System: If the Independent Transmission Provider determines that it cannot accommodate a request for service or Congestion Revenue Rights because of insufficient transmission capability on its Transmission System, the Independent Transmission Provider must use due diligence to expand or modify its Transmission System to provide the requested transmission service, provided the Customer agrees to compensate the Independent Transmission Provider for such costs pursuant to the terms of Section B.5.12. The Independent 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 obligation applies only to those facilities that the Independent Transmission Provider along with the Transmission Owner has the right to expand or modify.

5.10 Partial Interim Service: If the Independent Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for service, the Independent Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Network Access Service that can be accommodated without addition of any facilities and through redispatch. Partial service could be of an amount (MW) or duration. However, the Independent Transmission Provider shall not be obligated to provide the incremental amount of requested Transmission Service (or Congestion Revenue Rights) that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service. To the extent the Customer disagrees with the Independent Transmission Provider's determination of insufficient Available Transfer Capability (or redispatch capability), the Customer may request and the Independent Transmission Provider shall provide its workpapers and analysis.

5.11 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Customer shall have the option to expedite the process by requesting the Independent Transmission Provider to tender at one time, together with the results of required studies, an ''Expedited Service Agreement'' pursuant to which the Customer would agree to compensate the Independent Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the 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 Independent Transmission Provider agrees to provide the 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 Customer must agree in writing to compensate the Independent Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

5.12 Compensation for New Facilities: Whenever a System Impact Study performed by the Independent Transmission Provider in connection with the provision of Network Access Service identifies the need for new facilities, the Customer shall be responsible for such costs to the extent consistent with Commission policy.

6. Procedures if The Independent Transmission Provider is Unable to Complete New Transmission Facilities for Transmission Service

6.1 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 Independent Transmission Provider shall promptly notify the Customer. In such circumstances, the Independent Transmission Provider shall within thirty (30) days of notifying the Customer of such delays, convene a technical meeting with the Customer to evaluate the alternatives available to the Customer. The Independent Transmission Provider also shall make available to the Customer studies and work papers related to the delay, including all information that is in the possession of the Independent Transmission Provider that is reasonably needed by the Customer to evaluate any alternatives.

6.2 Alternatives to the Original Facility Additions: When the review process of Section B.5.5 determines that one or more alternatives exist to the originally planned construction project, the Independent Transmission Provider shall present such alternatives for consideration by the Customer. If, upon review of any alternatives, the Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Independent Transmission Provider to submit a revised Service Agreement for Network Access Service and a request for associated Congestion Revenue Rights. If the alternative approach solely involves Network Access Service and the Customer is willing to pay any applicable Congestion Charges, the Independent Transmission Provider shall promptly tender a Service Agreement for Network Access Service providing for the service. In the event the Independent Transmission Provider concludes that no reasonable alternative exists and the Customer disagrees, the Customer may seek relief under the dispute resolution procedures pursuant to Section A.10 or it may refer the dispute to the Commission for resolution.

6.3 Refund Obligation for Unfinished Facility Additions: If the Independent Transmission Provider and the 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 Transmission Service shall terminate and any deposit made by the Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Customer shall be responsible for all prudently incurred costs by the Independent Transmission Provider through the time construction was suspended.

7. Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

Part VI of this Tariff details Transmission Planning and Expansion.

8. Network Access Service Customer Responsibilities

8.1 Conditions Required of Customers: Network Access Service shall be provided by the Independent Transmission Provider only if the following conditions are satisfied by the Customer:

(i) The Customer has pending a Completed Application for service;

(ii) The Customer has met the creditworthiness and eligibility criteria set forth in Sections A.8 and A.9;

(iii) The Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Independent Transmission Provider prior to the time service under Part II of the Tariff commences;

(iv) The Customer has agreed to pay for any facilities constructed and chargeable to such Customer under Part II of the Tariff, whether or not the Customer takes service for the full term of its reservation; and

(v) The Customer has executed a Network Access Service Agreement or has agreed to receive service pursuant to Section B.2.9.

8.2 Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Customer requesting service. The Customer shall provide, unless waived by the Independent Transmission Provider, notification to the Independent Transmission Provider identifying such systems and authorizing them to schedule the capacity and Energy to be transmitted by the Independent 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 Independent Transmission Provider will undertake reasonable efforts to assist the Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

9. Load Shedding and Curtailments

9.1 Procedures: Prior to the Service Commencement Date, the Independent Transmission Provider and the Customer shall establish Load Shedding and Curtailment procedures in accordance with this Tariff with the objective of responding to contingencies on the Transmission System. The Parties shall implement such programs during any period when the Independent Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. [The Independent Transmission Provider shall notify all affected Customers and other market participants (*e.g.,* suppliers) in a timely manner of any scheduled Curtailment.]

9.2 Transmission Constraints: During any period when the Independent Transmission Provider determines that a transmission constraint exists on the Transmission System that cannot be handled through the LMP Congestion Management System, and such constraint may impair the reliability of the Independent Transmission Provider's system, the Independent Transmission Provider shall take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Independent Transmission Provider's system. To the extent the Independent Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Independent Transmission Provider shall initiate procedures to redispatch resources on the Independent Transmission Provider's Transmission System on a least-cost basis without regard to the ownership of such resources.

9.3 Curtailments of Scheduled Deliveries: If a transmission constraint on the Independent Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Independent Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Independent Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. To the extent operationally feasible, the Independent Transmission Provider shall curtail transactions in the following order. Parties who do not have Congestion Revenue Rights in adequate amounts for their Receipt Point-Delivery Point combinations, shall be curtailed first. All other transactions that have a material impact on the transmission constraint will be curtailed on a pro rata basis. [The

Independent Transmission Provider must develop procedures addressing non-discriminatory Curtailment of parallel flows involving more than one transmission system.]

9.4 Load Shedding: To the extent that a system Contingency exists on the Independent Transmission Provider's Transmission System and the Independent Transmission Provider determines that it is necessary for the Independent Transmission Provider and the Customer to shed Load, the Customers shall be directed by the Independent Transmission Provider to shed Load on a non-discriminatory basis to alleviate the Emergency/reliability contingencies.

(i) The Independent Transmission Provider will act first, whenever feasible, to direct Customers who have not met their assigned share of Resource Adequacy Requirements, pursuant to Section I of this Tariff, to shed load, before requiring other Customers to shed load, up to the amount of the lesser of: (1) The Resource deficiency; or (2) the Customers' Day-Ahead Energy market schedules. Failure to comply with the Independent Transmission Provider's direction to shed load shall subject Customers to the penalty provisions of Section I.6.3.

9.5 System Reliability: Notwithstanding any other provisions of this Tariff, the Independent Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Access Service without liability on the Independent 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 Access Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Independent Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Independent Transmission Provider's Transmission System, the Independent Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Access 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 Independent Transmission Provider will give the Customer as much advance notice as is practicable in the event of such Curtailment. [The Independent Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Customer fails to respond to established Load Shedding and Curtailment procedures. The Independent Transmission Provider can assess a penalty for failure to curtail after a reasonable period of time.]

10. Rates and Charges

For any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

10.1 Monthly Access Charge: The Customer that is a Load-Serving Entity shall pay a monthly Access Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Independent Transmission Provider's Annual Transmission Revenue Requirement specified in Part VIII. The Access Charge applies only to deliveries to load on the Independent Transmission Provider's System. The Access Charge does not apply to any deliveries to hubs, wheel throughs, or Exports to neighboring transmission systems.

10.2 Determination of Customer's Monthly Network Load: The Customer's monthly Load is its hourly Load coincident with the Independent Transmission Provider's Monthly Transmission System Peak.

10.3 Transmission Usage Charges: The Customer shall pay a Transmission Usage Charge for the quantity in MWh scheduled for Transmission Service. The Transmission Usage Charge will recover applicable Congestion Charges and losses, consistent with Sections F.3.3 and G.4.3, as applicable.

11. Operating Arrangements

11.1 Operation Under the Network Operating Agreement: The Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

11.2 Network Operating Agreement: The terms and conditions under which the Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part II 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 Customer within the Independent Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Independent Transmission Provider and the Customer (including, but not limited to, heat rates and operational characteristics of Resources, generation schedules for units outside the Independent Transmission Provider's Transmission System, interchange schedules, unit outputs for dispatch, 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 Customer shall either (i) self-supply, contract for, or purchase from the Independent Transmission Provider all necessary Ancillary Services consistent with Good Utility Practice, which satisfies NERC and the [applicable regional reliability council] requirements. The Independent Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included under Part VII.

11.3 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 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.

12. Reservation Priority for Existing Firm Service Customers

12.1 Right of First Refusal: Prior to the effectiveness of a full auction mechanism for all Congestion Revenue Rights, Congestion Revenue Rights will be allocated to Customers with long-term firm contracts under which the Customer continues to pay the Access Charge. To ensure that these Customers are able to maintain that right until the time that Congestion Revenue Rights are auctioned, existing firm service Customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take Network Access Service and agreeing to pay the Access Charge when the existing contract expires, rolls over or is renewed. If at the end of the contract term, the Independent Transmission Provider's Transmission System cannot accommodate all of the requests for Congestion Revenue Rights, the existing firm service Customer must agree to accept a contract term at least equal to a competing request by any new Customer and to pay the Access Charge, as approved by the Commission, for such service. This priority for existing firm service Customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer. This section will remain in effect until the Independent Transmission Provider places into effect an auction mechanism for allocating all Congestion Revenue Rights.

12.2 Notice of Rollover: Consistent with requests for new service described in Section B.2.1 of the Tariff, a Customer must submit its request to exercise rollover rights no later than sixty (60) days prior to the date the current service agreement expires.

C. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Service Areas affected by the transmission service. The Independent Transmission Provider is required to provide, and the Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch Service, (ii) Reactive Supply and Voltage Control from Generation Sources Service; and (iii) Energy Imbalance Service.

The Independent Transmission Provider is required to offer to provide the following Ancillary Services only to the Customer serving Load within the Independent Transmission Provider's Service Area (i) Regulation and Frequency Response Service, (ii) Operating Reserve-Spinning Reserve Service, and (iii) Operating Reserve-Supplement Reserve Service. The Customer serving Load within the Independent

Transmission Provider's Service Area is required to acquire these Ancillary Services, whether from the Independent Transmission Provider or a market operated by the Independent Transmission Provider, from a third party, or by self-supply. The Customer may not decline the Independent Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Customer must list in its Application which Ancillary Services it will purchase from the Independent Transmission Provider.

The Independent Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Customer's agent to secure these Ancillary Services from others or by operating a market for the services. The Customer may elect to (i) have the Independent Transmission Provider act as its agent and procure Regulation and Frequence Response Service and Operating Reserves through the markets in Part III or (ii) secure Regulation and Frequency Response Service and Operating Reserves from a third party or by self-supply when technically feasible.

1. Scheduling, System Control and Dispatch Service

This service is required to schedule the purchase, sale and movement of power through, out of, within, or into the Independent Transmission Provider's Service Area. This service can be provided only by the Independent Transmission Provider. The Customer must purchase this service from the Independent Transmission Provider. The charges for Scheduling, System Control and Dispatch Service are set forth below.

1.1 Billing Units and Calculation of Rates: The Independent Transmission Provider shall charge each Customer based on the product of:

(i) the Scheduling, System Control and Dispatch Service charge rates; and

(ii) the Customer's applicable billing units for the month, as follows: [Independent Transmission Provider to propose rate methodology.]

2. Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission System within acceptable limits, generation facilities under the control of the Independent Transmission Provider are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service (''Voltage Support Service'') must be provided for each Transaction on the Transmission System. The amount of Voltage Support Service that must be supplied with respect to the 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 Independent Transmission Provider. Voltage Support Service is to be provided directly by the Independent Transmission Provider. The methodologies that the Independent Transmission Provider will use to obtain Voltage Support Service and the associated charges for such service are set forth below. [To be provided by the Independent Transmission Provider.]

3. Regulation Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of Resources (generation and interchange) with Load in order to maintain scheduled Interconnection frequency. 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) as necessary to follow the moment-by-moment changes in Load. The obligation to maintain this balance between Resources and Load lies with the Independent Transmission Provider. Each Load-Serving Entity must either purchase this service through the Independent Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

The Independent Transmission Provider shall establish Day-Ahead and Real-Time Markets for Regulation to procure through the Day-Ahead and Real-Time Markets that portion of Regulation Requirement not met through Self-Supply. The full Regulation Requirement shall be cleared through the Day-Ahead Market. The Real-Time Market will provide an alternate supply for Regulation Service during the Operating Day where (i) Suppliers scheduled in the Day-Ahead Market are inadequate; (ii) a scheduled Supplier is unable to provide Regulation Service (*e.g.,* the Generator tripped); (iii) the demand for Regulation Service increases beyond the scheduled supply; or (iv) other adjustments to the supply or demand of Regulation can be efficiently made. The Independent Transmission Provider shall select Suppliers in the Real-Time Market, during the Operating Day, to provide Regulation Service for each hour in which an insufficient supply of Regulation Service exists or when a supplier Bidding in the Real-Time market can provide Regulation service at a lower cost than a supplier that has been scheduled in the Day-Ahead Market.

The Market Rules for the Day-Ahead Market for Regulation are set forth in Section F.4. The Market Rules for the Real-Time Market for Regulation are set forth in Section G.4.

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 the Independent Transmission Provider's Service Area. This service will be provided through the Real-Time Energy Market operated by the Independent Transmission Provider. The procedures that will be used are described in Part III below.

5. Operating Reserves

The Independent Transmission Provider shall provide procedures to establish adequate Operating Reserves that comply with applicable Reliability Rules. Operating Reserves are classified as follows:

(i) Spinning Reserve: Operating Reserves provided by Resources (Generation and Demand) located within the Independent Transmission Provider Service Area that are already synchronized to the Power System and can respond to instructions to change output level within ten (10) minutes;

(ii) Supplemental Reserve: Operating Reserves provided by Resources (Generation and Demand) that can respond to instructions to change output or consumption level within ten (10) minutes or some other specified time period.

Operating Reserves can be ranked in terms of quality. Spinning Reserves are a higher quality reserve product than Supplemental Reserves. Supplemental Reserves that can respond to instructions on a shorter time frame (*e.g.,* 10 minutes) than other Supplemental Reserves (*e.g.,* 30-minutes) also have a higher quality ranking. The Independent Transmission Provider must substitute higher quality operating reserves for lower quality operating reserves when it is economical to do so.

The Independent Transmission Provider shall establish Day-Ahead and Real-Time Markets for Operating Reserves. The full requirement for Operating Reserves shall be cleared through the Day-Ahead Market. The Real-Time Markets will provide an alternate supply for Operating Reserves during the Operating Day where (i) Suppliers scheduled in the Day-Ahead Market are inadequate; (ii) a scheduled Supplier is unable to provide Operating Reserves (*e.g.,* the Generator tripped); (iii) the demand for Operating Reserves increases beyond the scheduled supply; or (iv) other adjustments to the supply or demand of operating reserves can be efficiently made. The Independent Transmission Provider shall select Suppliers in the Real-Time Market, during the Operating Day, to provide Operating Reserves for each hour in which an insufficient supply of Operating Reserves exists or when a supplier Bidding in the Real-Time market can provide Operating Reserves at lower costs than a supplier than has been scheduled in the Day-Ahead Market.

The Market Rules for the Day-Ahead Markets for Operating Reserves are set forth in Sections F.5 and F.6. The Market Rules for the Real-Time Markets for Operating Reserves are set forth in Sections G.6 and G.7.

D. Congestion Revenue Rights

Preamble

A Congestion Revenue Right is a right held by a Customer which provides the Customer with a hedge against uncertain future Congestion Charges by paying the holder of the right a stream of specified congestion revenues. This section details the specific types of Congestion Revenue Rights, the specific properties of Congestion Revenue Rights, and how Congestion Revenue Rights are acquired.

1. Types of Congestion Revenue Rights

The Independent Transmission Provider shall make available, through the processes identified in Section D.3, Receipt Point-to-Delivery Point Congestion Revenue Right Obligation as described below. In addition, upon request of Market Participants, the Independent Transmission Provider shall make available Receipt Point-to-Delivery

Congestion Revenue Right Options as well as Flowgate Congestion Revenue Rights, as soon as technically feasible.

1.1 Receipt Point-to-Delivery Point Congestion Revenue Rights: A Receipt Point-to-Delivery Point right is specified by a Receipt Point and a Delivery Point, the total MW that are to be injected at the Receipt Point and withdrawn at the Delivery Point, whether the right is an Obligation or an Option, and the period of time for which the right is in effect.

1.1.1 Obligation Rights: Receipt Point-to-Delivery Point Congestion Revenue Right Obligations confer to the holder (i) the right to collect revenues equal to the applicable Marginal Congestion Component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is positive, and (ii) the obligation to pay an amount to the Independent Transmission Provider equal to the absolute value of the applicable Marginal Congestion Component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is negative.

1.1.2 Option Rights: Receipt Point-to-Delivery Point Transmission Option Rights confer to the holder the right to collect revenues equal to the applicable Congestion Charge component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is positive, but do not obligate the holder to pay the absolute value of the applicable Marginal Congestion Component of the hourly Transmission Usage Charge when the Marginal Congestion Component is negative.

1.1.3 Types of Receipt Points and Delivery Points: The Receipt Points and Delivery Points specified in the Receipt Point-to Delivery Point Congestion Revenue Right can be a Generator bus, a load bus, an Interface between the Independent Transmission Provider's Service Area and an adjacent Service Area, or a pre-defined set of buses (which can be either Zones or Hubs).

1.2 Flowgate Congestion Revenue Rights

1.2.1 Definition of Flowgates and Flowgate Rights: A Flowgate is a transmission facility (such as a transmission line or a transformer or some other component of the electrical network) or group of facilities (e.g., an Interface) that constrains the power transfer capability of the network. A Flowgate Right is specified by a portion of the total MW capability over a particular transmission Flowgate in a specified direction. Flowgate Rights entitle the holder to collect Congestion revenues (as determined consistent with Section F.3.5.2) associated with the specified MW flow over the identified Flowgate in the specified direction in the Day-Ahead Market.

2. Term of Congestion Revenue Rights

During the first two years of operation of the Independent Transmission Provider's Bid-based markets, the Independent Transmission Provider shall offer Congestion Revenue Rights for sale through the auction procedures in Section D.7 with terms of 1 year, 6 months, and 1 month. Beginning in the third year of operation of the Independent Transmission Provider's Bid-based markets, the Independent Transmission Provider shall offer Congestion Revenue Rights with terms of 10 years, 5 years, 1 year, 6 months, and 1 month. Upon request of Market Participants, the Independent Transmission Provider may also offer Congestion Revenue Rights for other terms. These term limitations will not apply to Congestion Revenue Rights acquired through the initial allocation procedures for implementation of Standard Market Design.

3. Scheduling Priority for Holders of Congestion Revenue Rights in the Event of Curtailment

In any hour in which the Independent Transmission Provider is unable to accept all requested schedules for Transmission Service at the applicable Day-Ahead Transmission Usage Charges, holders of Receipt Point-to-Delivery Point Congestion Revenue Rights shall have scheduling priority from their designated Receipt Points to their designated Delivery Points over Customers that do not hold Congestion Revenue Rights. [The Independent Transmission Provider shall develop a method for determining how to implement such priority, which shall be inserted here.]

4. Existing Transmission Contracts

Transmission Service pursuant to each Existing Transmission Contract shall be provided by the Independent Transmission Provider for the account of the Existing Transmission Contract Transmission Owner, acting as agent for the Existing Transmission Contract Customer. The Independent Transmission Provider shall assess to the Existing Transmission Contract Transmission Owner all charges and payments associated with providing Transmission Service pursuant to this Tariff. Consistent with the provisions of this Tariff, the Transmission Owner may acquire Congestion Revenue Rights to hedge against the Congestion costs associated with Transmission Service provided pursuant to its Existing Transmission Contracts.

4.1 Conversion of Existing Transmission Contracts: Upon the mutual agreement of the parties to any Existing Transmission Contract, the Existing Transmission Contract Customer may terminate its Existing Transmission Contract in exchange for receiving Congestion Revenue Rights previously held by the Transmission Owner to support the Existing Transmission Contract described in Section D.3 with the same MW level of service and with the same Receipt Points and Delivery Points and termination date as specified in the Existing Transmission Contract.

5. Allocation of Congestion Revenue Rights

5.1 Allocation of Congestion Revenue Rights: The aggregate set of Congestion Revenue Rights allocated to Customers shall not exceed an amount that is Simultaneously Feasible, as determined pursuant to Section D.5.8, in light of the total transmission capability in the Independent Transmission Provider's Service Area under normal operating conditions. In determining whether a set of Congestion Revenue Rights is Simultaneously Feasible, the Total Transfer Capability of the transmission system shall not be reduced by the transfer capability needed to support existing Customers.

5.2 Requirement to Conduct Periodic Auctions for Congestion Revenue Rights. The Independent Transmission Provider shall conduct periodic auctions over its OASIS, consistent with Section D.5, that will provide Bid-based markets to buy and sell Congestion Revenue Rights for a variety of terms. Each auction shall provide for the opportunity to buy and sell Receipt Point-to-Delivery Point Congestion Revenue Right Obligations, as described in Section D.1. Upon the request of Market Participants, auctions shall provide for the opportunity to buy and sell Receipt Point-to-Delivery Point Transmission Option Rights and Flowgate Rights, as soon as it is technically feasible to do so.

The periodic Congestion Revenue Rights auctions will also provide for the sale of Congestion Revenue Rights associated with transmission capability that becomes available after the initial allocation of Congestion Revenue Rights, for example, due to the expiration of initially allocated Congestion Revenue Rights.

[The Independent Transmission Provider shall file procedures which may have either an allocation of Congestion Revenue Rights or an allocation of auction revenues from the sale of Congestion Revenue Rights.]

6. Resale of Congestion Revenue Rights

All holders of Congestion Revenue Rights may resell their Congestion Revenue Rights outside the auction held pursuant to Section D.3.2. However, the Independent Transmission Provider shall make all Settlements with Primary Holders. Buyers of resold Congestion Revenue Rights that elect to become Primary Holders must meet the eligibility criteria in Section A.9 of this Tariff.

Sellers and potential buyers shall communicate all offers to sell and buy Congestion Revenue Rights, solely over the Independent Transmission Provider's OASIS.

7. Auctions for Congestion Revenue Rights

The Independent Transmission Provider shall conduct periodic auctions to allow Market Participants to buy and sell Congestion Revenue Rights.

7.1 General Description of the Auction Process: In each auction, Market Participants will have the opportunity to submit Bids to buy and sell Congestion Revenue Rights for a specified term. In each auction, the Independent Transmission Provider shall consider all Bids and shall select a combination of Bids that (i) is Simultaneously Feasible in light of the Transmission Capability that is expected to be available over the term of the transactions and (ii) maximizes the combined net economic value (as expressed in the Bids) of the selected Bids. In order to maximize the net economic value of the selected Bids, the auction shall allow for the reconfiguration of Congestion Revenue Rights. That is, the Congestion Revenue Rights that are offered for sale may be converted into Congestion Revenue Rights of a different type or with different Receipt and Delivery Points.

7.2 Frequency of Congestion Revenue Rights Auction: The Independent

Transmission Provider shall conduct an Auction for Congestion Revenue Rights no less frequently that once in every calendar month.

7.3 Responsibilities of the Independent Transmission Provider Prior to Each Auction

7.3.1 Establish Auction Rules: The Independent Transmission Provider shall use the auction rules and procedures consistent with this Tariff. [Independent Transmission Provider may file to add additional auction rules.]

7.3.2 Evaluate Creditworthiness: The Independent Transmission Provider shall evaluate each Bidder's ability to pay for Congestion Revenue Rights, consistent with the creditworthiness provisions of Section A.8. As a result of this evaluation, the Independent Transmission Provider shall state a limit before the auction on the value of the Congestion Revenue Rights that the entity may be awarded in the auction, and collect signed statements from each entity Bidding into the auction committing that entity to pay for any Congestion Revenue Rights that it is awarded in the auction. Bidders will not be permitted to submit Bids that exceed this allowable limit.

7.3.3 Information to be Made Available to Bidders: To aid Market Participants in their participation in the auction, the Independent Transmission Provider shall make the following information available before each auction:

(i) for each Generator bus, Load bus, external bus and Load Zone for each of the previous 5 years, if available, (a) the average Marginal Congestion Component of the LMP, relative to the Reference Bus, and (b) the average Marginal Losses Component of the LMP, relative to the Reference Bus;

(ii) for each of the previous two 6-month periods, (a) historical flow histograms for each of the closed Interfaces, and (b) historically, the number of hours that the most limiting facilities were physically constrained;

(iii)(a) Power Flow data to be used as the starting point for the auction, including all assumptions, (b) assumptions made by the Independent Transmission Provider relating to transmission maintenance outage schedules, (c) all limits associated with transmission facilities, contingencies, thermal, voltage and stability to be monitored as Constraints in the Optimum Power Flow determination, and (d) the Independent Transmission Provider summer and winter operating study results (non-simultaneous Interface Transfer Capabilities).

7.3.4 Other Responsibilities: The Independent Transmission Provider will establish an auditable information system to facilitate analysis and acceptance or rejection of Bids, to provide a record of all Bids, and to provide all necessary assistance in the resolution of disputes that arise from questions regarding the acceptance, rejection, award and recording of Bids. The Independent Transmission Provider will establish a system to communicate auction-related information to all auction participants.

The Independent Transmission Provider will receive Bids to buy Congestion Revenue Rights from any entity that meets the eligibility criteria established in this Tariff and will implement the auction Bidding rules previously established by the Independent Transmission Provider.

The Independent Transmission Provider will properly utilize an Optimal Power Flow program to determine the set of winning Bids for each auction and calculate the Market Clearing Price of all Congestion Revenue Rights at the conclusion of the auction, in the manner described in this Tariff.

7.4 Responsibilities of each Buying Bidder

7.4.1 Creditworthiness Information: Each Bidder must submit such information to the Independent Transmission Provider regarding the Bidder's creditworthiness as the Independent Transmission Provider may require consistent with Section A.8, along with a statement signed by the Bidder, representing that the Bidder is financially able and willing to pay for the Congestion Revenue Rights for which it is Bidding. The aggregate value of the Bids submitted by any Bidder into the auction shall not exceed that Bidder's ability to pay or the maximum value of Bids that Bidder is permitted to place, as determined by the Independent Transmission Provider (based on an analysis of that Bidder's creditworthiness).

Each Bidder must pay the Market Clearing Price for each Congestion Revenue Right it is awarded in the auction.

7.5 Responsibilities of Each Selling Bidder

7.5.1 Bids to Sell Congestion Revenue Rights: Each Market Participant desiring to sell Congestion Revenue Rights Shall include the following information in its Bid:

(i) The type of Congestion Revenue Right (i.e., Receipt Point-to-Delivery Point Congestion Revenue Right Obligation, Receipt Point-to-Delivery Point Transmission Option Right, or Flowgate Congestion Revenue Right).

(ii) The Receipt and Delivery Points, if a Receipt Point-to-Delivery Point Right is offered.

(iii) The location and direction of the Flowgate, if a Flowgate Right is offered.

(iv) The MWs

(v) The minimum acceptable price, if any.

(vi) The term.

Each seller that offers Congestion Revenue Rights for sale that it has been awarded must provide verification of the award to the Independent Transmission Provider when the Bid is submitted.

7.6 Selection of Winning Bids and Determination of the Market Clearing Price: The Independent Transmission Provider shall determine the winning set of Bids in each auction as the set of Bids that maximizes the value (as expressed in the Bids) of the Congestion Revenue Rights, subject to the constraint that the selected set of Bids must be simultaneously feasible consistent with Section D.5.8.

The Market Clearing Price for each Congestion Revenue Right shall equal the change in the net economic value of all other Bidders that would result from awarding an additional 1 MW of that Congestion Revenue Right to a Market Participant.

7.7 Auction Settlement: The Independent Transmission Provider will determine prices in the auction for feasible Congestion Revenue Rights, consistent with Section 6.6. Each Bidder awarded Congestion Revenue Rights in the auction shall pay the applicable Market Clearing Price for those Congestion Revenue Rights that is awarded in the auction. Similarly, each Congestion Revenue Right holder selling Congestion Revenue Rights through the Auction shall be paid the applicable Market Clearing Price for those Congestion Revenue Rights that are sold in the auction.

7.8 Simultaneous Feasibility: The set of winning Bids selected in each auction shall be simultaneously feasible based on the Transfer Capability available for purchase within the Independent Transmission Provider's Service Area under normal operating conditions. A set of Bids shall be deemed simultaneously feasible if both of the following Conditions, A and B, are met:

Condition A: Each set of injections and withdrawals associated with (i) winning, as well as outstanding previously-awarded, Receipt Point-to-Delivery Point Congestion Revenue Right Obligations along with (ii) any combination of winning, as well as previously awarded, Receipt Point-to-Delivery Point Congestion Revenue Right Option Rights, would not exceed any thermal, voltage, or stability limits within the Independent Transmission Provider's Service Area under normal operating conditions or for monitored contingencies.

Condition B: For each Flowgate in each direction, the power flow on the Flowgate in the specified direction resulting from the set of injections and withdrawals identified in Condition A, when added to the total Flowgate Rights awarded on the Flowgate in the specified direction, would not exceed the capability of the Flowgate available in the Auction.

The Power Flow simulations shall take into consideration the effects of parallel flows on the Transfer Capability of the Independent Transmission Provider's transmission system when determining which sets of injections and withdrawals are simultaneously feasible.

When performing the above Power Flows, injections for Receipt Point-to Delivery Point Congestion Revenue Rights that specify a Zone or a Hub as the injection location will be modeled as a set of injections at each bus in the injection Zone or Hub equal to the product of the number of Receipt Point-to-Delivery Point Congestion Revenue Rights and the percentage weights for each bus in the Zone or Hub.

When performing the above Power Flows, withdrawals for Receipt Point-to Delivery Point Congestion Revenue Rights that specify a Zone or Hub as the withdrawal location will be modeled as a set of withdrawals at each bus in the withdrawal Hub equal to the product of the number of Receipt Point-to Delivery Point Congestion Revenue Rights and the percentage weights for each bus in the Zone.

7.9 Responsibilities of the Independent Transmission Provider upon Completion of the Auction: The Independent Transmission Provider shall not reveal the Bid Prices submitted by any Bidder in the Auction until three months following the date of the auction, except as permitted by Section A.12. When these Bid Prices are posted, the names of the Bidders shall not be publicly revealed, but the data shall be posted in a way that permits third parties to track each individual Bidder's Bids over time.

Upon completion of the auction, the Independent Transmission Provider will collect payment for all Congestion Revenue Rights awarded in the auction. The Independent Transmission Provider will disburse the revenues collected from the sale of Congestion Revenue Rights to the Primary Holders upon completion of the Auction process. Each holder of a Congestion Revenue Right that offers that Congestion Revenue Right for sale in the auction shall be paid the Market Clearing Price for each Congestion Revenue Right sold by that holder. All remaining Auction revenues from the auction shall be allocated among those who pay the Access Charge. [The Independent Transmission Provider will file procedures explaining how these revenues will be allocated.]

8. Exchanging Congestion Revenue Rights

The Independent Transmission Provider shall allow a Customer to exchange its Receipt Point-to-Delivery Point Congestion Revenue Right Obligation for a different Receipt Point-to-Delivery Point Congestion Revenue Right Obligation with different Receipt and/or Delivery Points as long as the exchange meets the condition specified in Section D.6.1 is met. In addition, as soon as it is technically feasible, the Independent Transmission Provider shall allow a Customer to acquire Receipt Point-to-Delivery Point Transmission Option Rights and Flowgate Rights in exchange for other Congestion Revenue Rights that the Customer may hold, as long as the exchange meets the condition specified in Section D.6.1. The MW levels of the original Congestion Revenue Rights and the new Congestion Revenue Rights in the exchange need not be the same, as long as the exchange meets the condition specified in Section D.6.1.

8.1 Condition for Exchanging Congestion Revenue Rights: In order for the Independent Transmission Provider to approve a request to exchange Congestion Revenue Rights, pursuant to Section D.6, the new Congestion Revenue Right (after being exchanged for the original Congestion Revenue Right), in combination with all other outstanding Congestion Revenue Rights held by others, must be Simultaneously Feasible as defined in Section D.5.8 in light of the total Transmission Capability in the Independent Transmission Provider's Service Area under normal operating conditions.

9. Congestion Revenue Rights Associated with Transmission Expansions

The Independent Transmission Provider shall award to all Market Participants that fund additions to the transmission system Congestion Revenue Rights to equal the capability created by the expansion. The Congestion Revenue Rights awarded in combination with all other awarded Congestion Revenue Rights, must be Simultaneously Feasible as described in Section D.5.8 in light of the Total Transfer Capability available under normal operating conditions. Such Market Participants shall be allowed to choose any set of Receipt Point-to-Delivery Point Obligation Rights that meet the requirements for Simultaneously Feasibility. Such Market Participants shall also be allowed to choose any set of Receipt Point-to-Delivery Point Option Rights and Flowgate Rights that meet the requirements for Simultaneous Feasibility, as soon as it is it is feasible to issue such rights. Such Market Participants may elect to receive no Congestion Revenue Rights if, but only if, all outstanding Congestion Revenue Rights are Simultaneously Feasible in light of the Total Transfer Capability available after the additions under normal operating conditions. [The Independent Transmission Provider file a Commission-approved, non-discriminatory methodology for allocating Congestion Revenue Rights among multiple Market Participants that fund any single transmission capability addition.]

Part III. Day-Ahead and Real-Time Market Services

E. General Responsibilities and Requirements

Preamble

The Independent Transmission Provider will operate Day-Ahead and Real-Time Markets for Energy and certain Ancillary Services in conjunction with Day-Ahead and Real-Time markets for transmission services. These markets will allocate transmission Transfer Capability and Generation Capacity among competing uses in different markets through Locational Marginal Pricing (LMP). The markets will be operated jointly to ensure that the prices for the products and services are internally consistent. The procedures for operating these markets are detailed below.

1. Day-Ahead and Real-Time Market Services

This Part III contains the procedures for Bidding and Scheduling of Energy and Bid-Based Ancillary Services, Bilateral Transaction Schedules and Self-Schedules in the Day-Ahead Market. Part III also contains the time requirements, notice provisions and sequence followed in administering Day-Ahead financial Settlement. These scheduling requirements support the operations of the Day-Ahead Markets for Energy, Regulation and Frequency Response, and Operating Reserves, the determination of the Day-Ahead Transmission Usage Charge, and the Day-Ahead financial Settlement of Congestion Revenue Rights.

Part III also contains the procedures for Scheduling and Bidding of Energy and Bid-Based Ancillary Services, and modification of, or submission of new, Bilateral Schedules and Self-Schedules, that will be used following the close of the Day-Ahead Market. These procedures include the time requirements, notice provisions and sequence followed in administering Real-Time Financial Settlement. These Bidding and scheduling requirements support the operations of the Real-Time Markets for Energy, Regulation and Frequency Response, Operating Reserves, and the determination of the Real-Time Transmission Usage Charge.

2. Independent Transmission Provider Authority

The Independent Transmission Provider shall provide all Market Services for Energy, Ancillary Services, and Transmission Service in accordance with the terms of the Tariff and related agreements.

The Independent Transmission Provider shall be the sole point of Application for all Market Services for Energy, Ancillary Services, and Transmission Service provided in the Independent Transmission Provider's Service Area. Each Market Participant that sells or purchases Energy, including demand side Resources, provides Ancillary Services, or Schedules Transmission Services subject to Transmission Usage Charges in the Independent Transmission Provider Administered Markets, utilizes Market Services and must take service as a Customer under the Tariff.

The Independent Transmission Provider has the right to schedule and dispatch Scheduled Resources and to direct that schedules be changed in an Emergency.

Following the start of the markets, the Independent Transmission Provider shall have the right to file changes to these market rules with the Commission to improve the competitiveness and efficiency of the markets.

3. Informational and Reporting Requirements

The Independent Transmission Provider shall operate and maintain an OASIS that, among other things, will facilitate the posting of Bids to supply Energy, Ancillary Services and Demand Reductions by Suppliers for use by the Independent Transmission Provider and the posting of LMP, clearing prices for Bid-based Ancillary Services, and schedules for accepted Bids for Energy, Ancillary Services and Demand Reductions. The OASIS will be used to post schedules for Bilateral Transactions. The OASIS also will provide historical data regarding market clearing prices for each market in addition to Transmission Usage Charges.

4. Communication Requirements for Market Services

Customers may utilize a variety of communications facilities to access the Independent Transmission Provider's OASIS, including but not limited to, conventional Internet service providers, wide area networks, and dedicated communications circuits. Customers shall arrange for and maintain all communications facilities for the purpose of communication of commercial data to the Independent Transmission Provider. Each Customer shall be the Customer of record for the telecommunications facilities and services it uses and shall assume all duties and responsibilities associated with the procurement, installation and maintenance of the subject equipment and software.

F. Day-Ahead Scheduling and Markets

Preamble

The Independent Transmission Provider will operate a Day-Ahead Market in order to develop a joint Day-Ahead Schedule for Transmission Service, Energy, and Ancillary Services. The Day-Ahead Schedule will be developed so as to maximize the combined economic value of Transmission Service, Energy, and Ancillary Services, based on the Bids submitted.

1. Day-Ahead Scheduling Procedures

1.1 Day-Ahead Trading Deadline: Market Participants may submit Bids for purchase and sale of Energy, Ancillary Services and Transmission, Bilateral Transaction Schedules, Self-Schedules, and Ancillary Services Self-Supply Schedules no later than [to be supplied by Independent Transmission Provider] for use in establishing the Day-Ahead Schedule.

1.2 Rules for Self Schedules

1.2.1 Supplier-Committed Self Schedules

(i) Suppliers of Generation Resources for Energy may Self-Schedule these Resources in the Day-Ahead Markets.

(ii) Self-Schedules by Suppliers of Energy are required only to submit a MW quantity and a location.

1.2.2 Independent Transmission Provider-Committed Self Schedules

(i) Upon request of a Supplier, the Independent Transmission Provider shall develop a schedule for Generation or Demand Resources in which the Schedule optimizes the revenues over the Operating Day for the Resource. These are referred to in this Tariff as Independent Transmission Provider- Committed Self Schedules. This option will typically be used by Energy-Limited Resources, however this option is available to all Generation or Demand Resources.

(ii) Independent Transmission Provider-Committed Self-Schedules are required only to submit a MW quantity and a location.

1.2.3 Self Supply of Ancillary Services

(i) Suppliers of Resources for Regulation and Operating Reserves may Self-Supply these Resources in the Day-Ahead Markets.

(ii) The specific rules for Self-Supply of Regulation and Operating Reserves are in Sections F.4–F.6.

1.3 Rules for Bilateral Transactions Schedules

1.3.1 Internal Transactions

(i) All Internal Transactions must specify a Receipt Point, a Delivery Point, a MW quantity injected at the Receipt Point and a MW quantity withdrawn at the Delivery Point.

(ii) Internal Transactions may also, voluntarily, submit a price Bid ($/MW) over some or all of the MW range. This makes the transaction under the control of the Independent Transmission Provider.

1.3.2 External Transactions

(i) All External Transactions must specify a Receipt Point, a Delivery Point, a MW quantity injected at the Receipt Point and a MW quantity withdrawn at the Delivery Point. Either the Receipt Point or the Delivery Point must be a point at the boundary of the Independent Transmission Provider's Service Area. If the Receipt Point is a boundary point, then the External Transaction is an Import. If the Delivery Point is a boundary point, then the External Transaction is an Export. All External Transactions must specify a minimum run time.

(ii) The Independent Transmission Provider shall offer Market Participants with External Transactions two options for Day-Ahead scheduling. (1) External Transactions can be scheduled without a Price Bid. The Independent Transmission Provider shall take all appropriate steps to accommodate such transactions, such as reservation of ramping capacity. (2) External Transactions can be scheduled in the Day-Ahead Market with a Price Bid ($/MW) over some or all of the MW quantity being scheduled. Transactions with a Bid will only enter the Day-Ahead Schedule if the price is at or below the LMP at the transaction sink node.

(iii) External Transactions will be scheduled on a hourly basis.

1.4 Rules for Bidding: The Independent Transmission Provider shall evaluate all eligible Bids for Energy Supply and Demand, Regulation and Frequency Response, Operating Reserves and Day-Ahead Transmission Service. The requirements for Bid eligibility and the Bid Specifications are in Sections F.2.3, F.3.1, F.4.4, F.5.4 and F.6.4.

1.5 Bid-Based Security Constrained Unit Commitment and Determination of the Day-Ahead Schedule: The Independent Transmission Provider will develop a Security Constrained Unit Commitment schedule over the Operating Day using a computer algorithm that accepts all Self-Schedules and simultaneously maximizes the total value of the Bids, including Virtual Bids, submitted to (i) supply to (incorporating the costs of Start-up, No-load and Incremental Energy) and purchase from the Day-Ahead Market for Energy; (ii) provide sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market; and (iii) receive Transmission Service to support Bilateral Transaction schedules and Self-Schedules submitted Day-Ahead. The Independent Transmission Provider may substitute higher quality Ancillary Services (i.e., shorter response time) for lower quality Ancillary Services when doing so would result in an overall least Bid cost solution.

In developing the Day-Ahead Schedule, the Independent Transmission Provider shall select Suppliers for Energy, Regulation and Frequency Response, and Operating Reserves for each hour of the upcoming day through its Day-Ahead Security-Constrained Unit Commitment, using Bids and/or schedules provided by the Suppliers. The Day-Ahead schedule will include commitment of sufficient Generators and price-sensitive Demand Bids to provide for the safe and reliable operation of the power system operated by the Independent Transmission Provider. The schedule shall honor all operating constraints included in the scheduled Bids. The Day-Ahead schedule shall list the twenty-four (24) hourly injections and withdrawals for: (a) each Customer whose Bid the Independent Transmission Provider accepts for the following Operating Day; and (b) Self-Schedules of Energy, Ancillary Services, and Transmission Service.

1.6 Determination of the Day-Ahead Prices: The Independent Transmission Provider shall calculate the Day-Ahead Energy LMPs and Flowgate LMPs based on a dispatch of committed Generation Resources to meet the Load that has Bid in and been scheduled Day-Ahead. The Day-Ahead Energy LMPs are calculated, according to the Independent Transmission Provider decision, for each Generator bus, load bus, and sets of buses that comprise Zones or Hubs. The Transmission Usage Charge for Bilateral Transactions that are scheduled Day-Ahead is the difference between the Energy LMP for the Delivery Point and the Energy LMP at the Receipt Point. The methodology for calculating the different types of LMPs is described in Sections F.2.4 and 3.3.

The Day-Ahead prices for Ancillary Services will be determined according to procedures described in Sections F.4.5, 5.5, 6.5 and 6.6.

1.7 Load Forecasts: All Load-Serving Entities shall provide their Day-Ahead Load forecasts to the Independent Transmission Provider. The Independent Transmission Provider shall develop an advisory forecast based on these forecasts and its own analysis of next day Load and shall post this forecast.

1.8 Reliability-Based Security Constrained Unit Commitment: In cases in which the sum of all Bilateral Schedules and all Day-Ahead Market purchases to serve Load within the Independent Transmission Provider's Service Area in the Day-Ahead schedule is less than the Independent Transmission Provider's Day-Ahead forecast of Load, the Independent Transmission Provider will commit Resources in addition to the reserves it normally maintains to enable it to respond to contingencies. These additionally-committed Resources are called Replacement Reserves. This commitment of Replacement Reserves will be the result of a Bid-Based Reliability-Based Security Constrained Unit Commitment conducted following the Day-Ahead Security Constrained Unit Commitment. The purpose of this additional commitment of Resources is to ensure that sufficient capacity is available to the Independent Transmission Provider in Real-Time to enable it to meet its Load forecast (including associated Ancillary Services).

In considering which additional Resources to schedule to meet the Independent Transmission Provider's Load forecast, the Independent Transmission Provider will evaluate whether unscheduled Imports can provide additional power at a price within any Bid Price caps set by the Independent Transmission Provider.

The Independent Transmission Provider will develop the Reliability-Based Security Constrained Unit Commitment schedule over the Operating Day using a computer algorithm that minimizes the total cost of committing the additional Generation and Demand Resources that provide Replacement Reserves based solely on the Start-up and No-load Bids of the additionally committed Resources. The Independent Transmission Provider shall use Bids submitted into the Day-Ahead Market. If such Bids are not sufficient to meet the forecast load, the Independent Transmission Provider may solicit additional Bids; these additional Bids will be considered eligible for the Real-Time Market in addition to the Reliability-Based Security Constrained Unit Commitment. Resources committed in the Reliability-Based Security Constrained Unit Commitment are obligated to Start-up and operate at their No-load level.

1.9 Reliability Forecast: In the Security Constrained Unit Commitment program, system operation shall be optimized based on Bids over the Operating Day. However, to preserve system reliability, the Independent Transmission Provider may take steps to ensure that there will be sufficient Resources available to meet forecasted Load and reserve requirements over the day beginning with the next Operating Day, typically completing a one week look ahead.

1.10 Posting the Day-Ahead Schedule: By [a pre-defined deadline to be supplied by Independent Transmission Provider] on the day prior to the Operating Day, the Independent Transmission Provider shall close the Day-Ahead scheduling process and post on its OASIS the Day-Ahead schedule for Energy, Regulation and Frequency Response, and Operating Reserves for each entity that submits a Bid or Self-Schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer and Transmission Owners subject to the applicable Code of Conduct. The Independent Transmission Provider will post on the OASIS the aggregate Resources (Day-Ahead Energy, Regulation and Frequency Response and Operating Reserves schedules) and Load (Day-Ahead scheduled and forecast) for each Load bus or Zone, and the Day-Ahead LMP prices (including the Marginal Congestion cost Component and the Marginal Losses component) for each Generation Bus, Load Bus or Load Zone and Hub in each hour of the upcoming Operating Day.

The Independent Transmission Provider shall conduct the Day-Ahead Settlement based upon the Day-Ahead Prices determined in accordance with this Section.

1.11 Day Ahead Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall ensure the minimum recovery of each Resource's Bid prices for Resources scheduled through the Day-Ahead Market or in subsequent commitments for reliability. The is called the Bid Revenue Sufficiency Guarantee.

(i) The Independent Transmission Provider shall determine, on a daily basis, if any Resource committed by the Independent Transmission Provider in the Day-Ahead Market will not recover Start-Up, No Load, and Energy Bid Price through revenues in the Day-Ahead Energy and Ancillary Services markets.

(ii) If the Start-Up and No Load Bids plus the net Energy and Ancillary Services Bid Price over the twenty-four (24) hour day of any Supply Resource exceeds the sum of its Day-Ahead LMP revenue and Ancillary Service revenue over the twenty-four (24) hour day, then that Supplier's Day-Ahead LMP revenue and Ancillary Service revenue shall be augmented by an additional payment, the Supply Bid Revenue Sufficiency Guarantee Payment, in the amount of the shortfall. This payment shall be supported through revenue collected from the Supply Bid Revenue Sufficiency Guarantee Charge.

(iii) If the total Day-Ahead Energy charges to any Demand Resource over the twenty-four (24) hour day exceeds its maximum willingness to pay, as reflected by the difference of its selected Day-Ahead Energy Bids and Start-up Cost Bid, the Demand Resource shall be augmented by a payment, the Demand Bid Revenue Sufficiency Guarantee Payment, in the amount of the overcharge. This payment is supported through revenues collected from the Demand Bid Revenue Sufficiency Guarantee Charge.

2. Day-Ahead Market for Energy

2.1 General: The Day-Ahead Market for Energy establishes clearing prices and settlement rules for Suppliers of Energy that have offered eligible Generation Capacity to the market and for Purchasers of Energy that have chosen not to Self-Supply or procure through bilateral contracts.

2.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (v) for the Day-Ahead Market for Energy. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS rules that are consistent with this Tariff for eligibility to supply Energy in the Day-Ahead Market.

(ii) Establish and post on its OASIS the Bid data requirements and rules and provide the market functions that are consistent with this Tariff required for determination of hourly Day-Ahead LMPs for Energy and selection of Day-Ahead Energy Market Suppliers and Purchasers.

(iii) Establish and post on its OASIS the rules that are consistent with this Tariff for determination of any additional payments necessary to support efficient operations of the Day-Ahead Market for Energy and/or the efficient operation of other Day-Ahead Markets.

(iv) Provide the Settlement functions associated with purchase and sale of Energy in the Day-Ahead Market.

(v) Post the Day-Ahead LMPs for Energy.

2.3 Purchaser Rules and Obligations: Purchasers of Energy in the Day-Ahead Market shall provide the Bid information specified in Sections 2.3.1 to 2.3.3.

2.3.1 Specification of Bids: Purchasers of Day-Ahead Energy must provide the following Bid information. Purchasers must supply all information that is identified as a required Bid component. Purchasers may, but are not required to, submit information that is identified as an optional Bid component.

(i) MW desired to be purchased, with a default value of 0 MW. This is a required Bid component.

(ii) Location (transmission zone, aggregate, or single bus) that the purchaser desires to purchase the designated MWs of power. This is a required Bid component.

(iii) Maximum price ($/MW) at which the purchaser desires to purchase the designated MW of power. (A purchaser may indicate its desire to purchase the designated MWs of power regardless of price, if the purchaser has demonstrated to the Independent Transmission Provider in advance that it is financially capable of paying the highest possible price for the designated MWs.) This is a required Bid component.

(iv) Start-up Cost ($). This Bid component is an additional payment needed by the Purchaser of Energy to curtail its load This is an optional Bid component.

(v) Minimum Curtailment Time (hours). This Bid component is up to a maximum of 24 hours. This is an optional Bid component. If a Minimum Curtailment Time is not indicated, then the default time will be one hour.

(vi) Maximum Curtailment Time (hours). This Bid component is up to a maximum of 24 hours. This is an optional Bid component. If a Maximum Curtailment Time is not indicated, then the default time will be 24 hours.

(vii) Minimum Purchase Time (at least one hour). This is an optional Bid component

(viii) Maximum Purchase Time (hours). This is an optional Bid component.

(ix) Hours that the purchaser desires to purchase the designated MWs of power. This is a required Bid component.

2.3.2 Specification of Virtual Bids: Purchasers of Day-Ahead Virtual Energy must provide Bid components 2.3.1 (i) to (iii). In addition, the Bid shall identify that the Energy purchase is Virtual Energy if the purchase is not backed by actual load.

2.3.3 Period of Bids: The Demand Bids shall be hourly Bids for each hour of the Operating Day in which the price ($) and quantity (MW) components can vary hour by hour.

2.4 Supplier Rules and Obligations

2.4.1 Eligibility to Supply: Suppliers of Day-Ahead Energy shall provide the Bid information specified in Section 2.4.2 . Suppliers of Day-Ahead Virtual Energy shall provide the Bid information specified in 2.4.3- 2.4.4 .

2.4.2 Specification of Bids. Suppliers are required to include the following price, quantity and data components in their Generation Bid. Suppliers must supply all information that is identified as a required Bid component. Suppliers may, but are not required to, submit information that is identified as an optional Bid component. The Bid Data requirements are additional data on Generator characteristics needed by the Independent Transmission Provider for market operations and reliability purposes.

Bid Prices and Quantities

(i) Start-Up ($). This is an optional Bid component (Market Participants can opt to exclude Start-up Costs in their Energy Bid by setting this cost to $0). Limits on the frequency with which Start-up Bid Costs can be changed must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(ii) Minimum Generation (No-load) ($/hour). This is an optional Bid component (Market Participants can opt to exclude No-load Costs in their Energy Bid by setting this cost to $0/hour). Limits on the frequency with which Minimum Generation Bid Costs can be changed must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(iii) Incremental Energy ($/MWh). Market Participants must provide prices for the full MW range of their Operable Capacity, from the Hourly Economic Minimum Level to the

Hourly Economic Maximum Level. This is a required Bid component. [Independent Transmission Provider may add requirements regarding the number of steps or pieces in the Bid function.] The Incremental Energy Bid may be negative, indicating the price that the Supplier is willing to pay for the Generator not to be dispatched below its Hourly Economic Minimum Level. The upper limit on the Bid price of Incremental Energy over the full MW range of the Operable Capacity must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation. Any other limits on the Bid price of Incremental Energy must also be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(iv) Emergency Incremental Energy ($/MWh). Market Participants must provide a price for the Emergency MW range of their Operable Capacity, from the Hourly Economic Maximum Level to the Hourly Emergency Maximum Level. This is a required Bid component. The upper limit on the Bid price of Emergency Incremental Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation. Pricing rules for Emergency uses of Generation Resources are in Section G, 3.7(iii).

Bid Data Requirements

(v) Normal Response Rate (MW/min). The expected response rate for Security Constrained Dispatch. This is a required Bid component.

(vi) Regulation Response Rate (MW/min). The response rate for units providing regulation. This is a required Bid component for Resources offering Regulation service.

(vii) Hourly Economic Minimum Level (MW). This is a required Bid component. Limits on the frequency with which the Hourly Economic Minimum Level can be changed must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(viii) Hourly Economic Maximum Level (MW). This is a required Bid component.

(ix) Hourly Emergency Minimum Level (MW). This is the Minimum Level for a Generator in the event of an Emergency. This is a required Bid component.

(x) Hourly Emergency Maximum Level (MW). This is the Maximum Level for a Generator in the event of an Emergency. This is a required Bid component.

(xi) Start-up Time (hours). The number of hours required to start the Generator. This is a required Bid component.

(xii) Minimum Run Time (hours). This Bid component is up to a maximum of 24 hours. This is a required Bid component. Limits on the Minimum Run Time of particular Generators must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(xiii) Maximum Run Time (hours). This is an optional Bid component.

(xiv) Minimum Down Time (hours). This is an optional Bid component.

(xv) Maximum Start-up Limit or Maximum Shut Down Limit in 24 Hours (integer number). This is an optional Bid component.

(xvi) Location.

2.4.3 Bids to Supply Virtual Incremental Energy

(i) A Virtual Incremental Energy Bid ($/MWh) is an Incremental Energy Bid that specifies that the Bid is a Virtual Transaction, *i.e.,* it is not backed by a physical supply Resource. Virtual Incremental Energy Bids must include (1) a price, (2) a MW quantity, and (3) a location. The upper limit on the Bid price of Virtual Incremental Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

2.4.4 Bids to Supply Decremental Energy

(i) A Decremental Energy Bid ($/MWh) is a Bid to reduce the output of a Generator. Decremental Energy Bids must include (1) a price, (2) a MW quantity, and (3) a location. The upper limit on the Bid price of Decremental Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(ii) A Virtual Decremental Energy Bid ($/MWh) is a Decremental Energy Bid that specifies that the Bid is a Virtual transaction. The upper limit on the Bid price of Virtual Decremental Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(iii) A Decremental Emergency Energy Bid ($/MWh) is a Decremental Energy Bid to reduce the output of a Generator below its Hourly Economic Minimum Level down to its Hourly Emergency Minimum Level. The upper limit on the Bid price of Decremental Emergency Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation. Pricing rules for Emergency uses of Generation Resources are in Section G, 3.7(iii).

2.4.5 Period of Bids to Supply Energy: A Customer may submit Bids to Supply Incremental Energy or Decremental Energy pursuant to Sections F.2.4.2–2.4.4 that can vary by price ($) and quantity (MW) in each Hour of the Day-Ahead Market.

2.5 Calculation of Day-Ahead Locational Marginal Prices for Energy

The Independent Transmission Provider shall calculate the price of Energy at the Load buses and Generation buses in the Independent Transmission Provider Service Area and at the Interface buses between the Independent Transmission Provider Service Area and adjacent Service Areas on the basis of Energy LMPs. LMPs can be set by Bids to sell or purchase Energy, including External Transaction Imports with Bids, and by transmission Bids. If requested by Market Participants the Independent Transmission Provider will establish Hubs and Zones based on a pre-defined set of buses. The Independent Transmission Provider will calculate load-weighted average Energy LMPs for this pre-defined set of buses, defined as Hub Prices or Zone Prices (or Zonal-LMPs). The Energy LMPs, Hub Prices and Zone Prices shall include separate components for the marginal costs of Congestion and the marginal costs of losses. Energy LMPs determined in accordance with this Section shall be calculated and posted on a Day-Ahead basis for each hour of the Day-Ahead Energy Market by [time to be provided by Independent Transmission Provider].

2.5.1 Energy LMP Calculation: The Independent Transmission Provider will calculate for each bus on its system in each hour the Energy LMP, equal to the marginal cost of making an additional increment of Energy available at the bus in the hour, based on the Bids of sellers and buyers selected in the Day-Ahead Security Constrained unit Commitment for Energy supply and purchase. The Independent Transmission Provider shall designate one bus as the Reference Bus, *r*, for all other buses in the system. The System Marginal Price (SMP_r), is the cost of making an additional increment of Energy available to the Reference Bus, based on Bids selected in the Day-Ahead Security Constrained Unit Commitment for Energy supply and Purchase. For each bus other than the Reference Bus, the Independent Transmission Provider shall determine separate components of the Energy LMP for the marginal costs of Congestion and losses relative to the Reference Bus, consistent with the following equation:

$$\text{Energy LMP}_i = SMP_r + MCC_i + MLC_i,$$

where SMP_r is the system marginal price in each hour at the Reference Bus, *r,* in the system, MCC_i is the LMP component representing the marginal cost of Congestion at bus *i* relative to the Reference Bus, and MLC_i is the LMP component representing the marginal cost of losses at bus *i* relative to the Reference Bus.

(i) Calculation of Marginal Congestion Component: The Independent Transmission Provider will calculate the marginal costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Congestion Component (MCC) component of the Energy LMP at bus *i* is calculated using the equation:

$$\mathrm{MCC_i} = -\left(\sum_{k=1}^{K} \mathrm{GSF_{ik} FMP_k}\right),$$

where: *K* is the number of thermal or Interface Transmission Constraints; GSF_{ik} is Shift Factor for the Generator at bus *i* on Flowgate *k* which limits flows across that Constraint when an increment of power is injected *i* and an equivalent amount of power is withdrawn at the Reference Bus, and FMP_k is the Flowgate LMP on Flowgate *k* and is equivalent to the reduction in system cost expressed in $/MWh that results from an increase of 1 MW of the capacity on Flowgate k.

(ii) Calculation of Marginal Losses Component: The Independent Transmission Provider will calculate the Marginal Losses Component (MLC) at each Load bus i. The MLC of the LMP at any bus i within the Independent Transmission Provider Service Area is calculated using the equation:

$$\mathrm{MLC_i} = \left(\mathrm{DF_i} - 1\right) \mathrm{SMP_i},$$

where DF_i = delivery factor for bus *i* to the system Reference Bus, and $DF_i = (1 - \partial L/\partial G_i)$, where: L is system losses, G_i is generation injection at bus *i,* $\partial L/\partial G_i$ is the partial derivative of system losses with respect to generation injections at bus *i,* that is, the incremental change in system losses associated with an incremental change in the generation injections at bus *i* holding constant other injections and withdrawals at all buses other than the Reference Bus and bus *i*.

2.5.2 Hub Price Calculation: If requested by Market Participants, the Independent Transmission Provider shall calculate a Hub Price based on the Energy LMPs for a set of buses that comprise the Hub. These Hub Prices are the weighted average of the Energy LMPs at the buses that comprise the Hub. The weights will be pre-determined by the Independent Transmission Provider and remain fixed. [The Independent Transmission Provider may add procedures for determining the buses that comprise the Hub and procedures for changing the weights over time.] The Price for Hub *j* can be written as:

$$\text{Hub Price}_j = \sum_{i=1}^{n} \left(W_{Hi} \times \text{LMP}_i \right),$$

where *n* is the number of buses in Hub_j and W_{Hi} is the weighting factor for bus *i* in Hub *j*. The sum of the weighting factors shall add up to 1.

2.5.3 Zone Price Calculation

(i) If requested by Market Participants, the Independent Transmission Provider shall calculate a Zone Price based on the Energy LMPs for a set of buses that comprise the Zone. These Zone Prices are the weighted average of the Energy LMPs at the set of buses that comprise the Zone. The Zone bus weights will equal the fractional share of each load bus in the total load in the Zone in the Hour. [The Independent Transmission Provider may add procedures for determining the buses that comprise the Zone, and assigning weights to those buses, in response to changes in retail load.]

$$\text{Zone Price}_j = \sum_{i=1}^{n} \left(W_{Zi} \times \text{LMP}_i \right),$$

where *n* is the number of Load buses in Zone *j* and W_{Zi} is the load weighting factor for bus *i* in Zone *j*. The sum of the weighting factors adds up to 1.

(ii) If the Zone price is used for Settlement purposes, it is subject to the following rules. (1) Each Zone shall include only the buses of Market Participants who agree to be in the Zone (and thus, who agree that their settlements will be calculated based on the zonal price). Alternatively, any one zone shall include only the buses of a single Market Participant. (2) A Market Participant who wants to be billed at a Zonal Price must include in its Zone all of the buses where Energy deliveries will be billed at the Zonal Price. A Market Participant shall not be allowed to settle Energy purchases at a bus or aggregation of buses if that bus or buses are not included in the Zone.

2.6 Calculation of Additional Payments and Charges

2.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate, for each Resource scheduled for Energy in the Day-Ahead Market, the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section F.1.11.

2.6.2 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Day-Ahead Market for Energy.]

2.7 Market Rules for Shortages or Emergencies

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities of Energy purchased, calculation of market prices, and determination of out-of-market payments in the event of a shortfall in Energy due to a shortage of available capacity. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) [The Independent Transmission Provider may include in this section procedures for soliciting additional Bids for Energy in the event that Bids and self-scheduled provision of Energy submitted in the Day-Ahead Markets fall short of the Bid-in Load.]

2.8 Settlement

2.8.1 Payments by Purchasers

(i) Each purchaser of Day-Ahead Energy shall be charged for all of its Load scheduled to be served from the Independent Transmission Provider's Day-Ahead Energy Market at the Day-Ahead LMPs applicable to each relevant Load bus and hour.

(ii) If a Market Buyer elects to calculate and settle Energy purchases at Zonal-LMPs, and the Zonal price meets the conditions for settlement specified in Section 2.4(c)(ii), then the market buyer shall be charged for all of its load scheduled to be served from the Day-Ahead Energy Market at the Day-Ahead Zonal-LMPs applicable to each relevant Load Zone and time period.

(iii) On any day when a Market Participant is scheduled to purchase any Energy in the Day-Ahead Market for Energy and/or does not Self-Supply a sufficient amount of its forecasted obligation (based on the Day-Ahead Schedule) for Regulation and Operating Reserves, the Market Participant shall be charged a Day-Ahead Bid Revenue Sufficiency Guarantee Charge. The Market Participant's Day-Ahead Supply Bid Revenue Sufficiency Guarantee Charge on any given day shall equal the product of (i) the Market Participant's total load (in MWh) scheduled in the Day-Ahead Market (which shall equal the sum of the Market Participant's total purchases of Energy in the Day-Ahead Market for Energy plus the Market Participant's total load scheduled to be met from Bilateral Transactions) and (ii) the per unit Day-Ahead Supply Bid Revenue Sufficiency Guarantee Charge.

The per unit Day-Ahead Supply Bid Revenue Sufficiency Guarantee Charge for any given day shall equal (i) the aggregate Bid Revenue Sufficiency Guarantee payments payable to Resources in the Day-Ahead Market for that day, divided by (ii) the sum of the total loads (in MWh) of all Market Participants that are to be charged Day-Ahead Supply Bid Revenue Sufficiency Charges for that day.

2.8.2 Payments to Suppliers

(i) Suppliers of Day-Ahead Energy shall be paid for all Energy scheduled to be delivered in the Day-Ahead Energy Market at the Day-Ahead LMPs applicable to each relevant generation bus.

(ii) The Independent Transmission Provider shall pay Suppliers any additional payments necessary to provide Day-Ahead Energy in accord with efficient market operations, as specified in Section 2.5

2.8.3 Payments by Suppliers

(i) Market Participant's Day-Ahead Demand Bid Revenue Sufficiency Guarantee Charge on any given day shall equal the product of (i) the Market Participant's total quantity (in MWh) scheduled in the Day-Ahead Market (which shall equal the sum of the Market Participant's total sales of Energy in the Day-Ahead Market for Energy plus the Market Participant's total supply scheduled to be met from Bilateral Transactions) and (ii) the per unit Day-Ahead Demand Bid Revenue Sufficiency Guarantee Charge.

The per unit Day-Ahead Demand Bid Revenue Sufficiency Guarantee Charge for any given day shall equal (i) the aggregate Demand Bid Revenue Sufficiency Guarantee payments payable to Resources in the Day-Ahead Market for that day, divided by (ii) the sum of the total supply (in MWh) of all Market Participants that are to be charged Day-Ahead Demand Bid Revenue Sufficiency Guarantee Charges for that day.

3. Day-Ahead Scheduling of Transmission and Settlement Functions for Congestion Revenue Rights

3.1 General: Day-Ahead scheduling of Transmission Service allows Market Participants to obtain Transmission Service to support Bilateral Transactions. This section establishes (1) rules for Bidding and/or scheduling Transmission Service, (2) determining prices (*i.e.*, Transmission Usage Charges, Transmission Usage Charges) for Transmission Service, and (3) settling with Market Participants that are scheduled for Transmission Service in the Day-Ahead Market. The Day-Ahead Energy LMPs shall be used to provide (1) the prices for sales and purchases of Energy and (2) Transmission Usage Charges (Transmission Usage Charges) for Transmission Service to support Bilateral Transactions. Because Transmission Usage Charges are based on the differences between Energy LMPs at the point of injection and point of withdrawal associated with an internal or external Bilateral Transaction, in their schedules requesting Transmission Service, Market Participants have the right to express willingness to pay for the Transmission Usage Charges—or equivalently, for the differences in the Energy LMPs.

In addition, the Day-Ahead Energy LMPs and Flowgate LMPs are used for Settlement of Congestion Revenue Rights. Holders of Receipt Point-to-Delivery Point Congestion Revenue Rights that seek to settle them against Real-Time Energy LMPs can do so by scheduling transactions in the Day-Ahead Energy Market.

3.2 Day-Ahead Transmission Requests

3.2.1 Information Provided by the Customer: Each Customer seeking to be scheduled for Transmission Service in the Day-Ahead Market shall be required to provide the Independent Transmission Provider the information in (i) through (iii) below. In addition, the Customer shall be required to provide the information either in (iv) or (vi), or both. The Customer shall provide this information separately for each transaction involving a different Receipt and/or Delivery Point. The Customer shall have the option of providing the information in (v).

(i) MW to be transmitted;

(ii) The Point of Receipt and the Point of Delivery;

(iii) The hours when the power is to be transmitted;

(iv) The maximum Transmission Usage Charge ($ per MW) that the Customer is willing to pay to receive the Transmission Service. The Customer may indicate that it desires the indicated Transmission Service regardless of the Transmission Usage Charge, if the Customer has demonstrated to the Independent Transmission Provider that it is capable of paying the highest possible Transmission Usage Charge. The Customer may separately indicate the maximum Charge for Marginal Costs of Congestion and the maximum charge for Marginal Losses that it is willing to pay.

(v) The minimum number of consecutive hours that the Customer desires to receive the Transmission Service.

(vi) The maximum total Transmission Usage Charge (in $ per MW) that the Customer is willing to pay to receive Transmission Service over the total number of scheduled hours.

(vii) Whether the Customer desires to provide additional Energy at the receipt point, in an amount that reflects the Marginal Losses associated with the Transmission Service (which the Independent Transmission Provider shall determine at the close of the Day-Ahead Market) in lieu of paying the charge for Marginal Losses.

3.3 Calculation of Day-Ahead Transmission Usage Charges: The Independent Transmission Provider shall charge a Transmission Usage Charge to all Bilateral Transactions whose transmission service was scheduled in the Day-Ahead Market. This charge is the product of (a) the amount of Energy scheduled to be withdrawn by that Customer in each hour in MWh; and (b) the Day-Ahead LMP at the Point of Delivery (which could be a Load Zone in which Energy is scheduled to be withdrawn or the external bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the Independent Transmission Provider Service Area), minus the Day-Ahead LMP at the Point of Receipt, in $/MWh. The Independent Transmission Provider shall divide each Transmission Usage Charge into separate components for Marginal Costs of Congestion and Marginal Costs of Losses.

3.3.1 Marginal Congestion Component: The Marginal Congestion Component of the Transmission Usage Charge shall be calculated as the Marginal Congestion Component of the Day-Ahead LMP at the Delivery Point minus the Marginal Congestion Component of the Day-Ahead LMP at the Receipt Point, as described in Section F.2.5(i).

3.3.2 Marginal Losses Component: The Marginal Losses Component of the Transmission Usage Charge shall be calculated as the Marginal Losses Component of the Day-Ahead LMP at the Delivery Point minus the Marginal Losses Component of the Day-Ahead LMP at the Receipt Point, as described in Section F.2.5(ii).

3.4 Flowgate LMP Calculation: The Independent Transmission Provider will, in addition to the calculation of the Energy LMPs, calculate Flowgate Locational Marginal Prices (FMPs) on the set of transmission constraints. The calculation for the Flowgate LMP (FMP) for each Transmission Constraint is defined in Section F.2.5.1(i). Independent Transmission Providers that offer Flowgate Rights must also calculate the Day-Ahead Flowgate LMPs (FMPs) on the Transmission Elements designated as Flowgates, based on a weighted average of the Transmission LMPs on the Transmission Elements that comprise the Flowgate:

$$\text{Marginal Price on Flowgate } f = \sum_{k=1}^{m} \left(W_k \times FMP_k \right),$$

where: f is the index of Flowgates; k is a Transmission Element in the set of Flowgates, K; m is the subset of the Transmission Elements that comprise Flowgate f; and W_k are the weights attached to each of the m Transmission Elements that comprise Flowgate f. The sum of the weighting factors adds up to 1. For Flowgates comprised of one Transmission Element, the W_k for that element is equal to 1. The Independent Transmission Provider shall determine the W_k for Transmission elements defined as Flowgates.

3.5 Settlement of Congestion Revenue Rights

3.5.1 Settlement of Receipt Point-to-Delivery Point Congestion Revenue Rights: For each hour in the Day-Ahead Market, the Independent Transmission Provider shall determine the Marginal Congestion Component of each Transmission Usage Charge associated with Transmission Service from a designated Receipt Point to a designated Delivery Point specified in each Receipt Point-to-Delivery Point Congestion Revenue Right (including both Obligation and Option Rights), consistent with Section F.3.3.1. In each instance when the applicable Marginal Congestion Component is positive, the Independent Transmission Provider shall pay to the Primary Holder of the Congestion Revenue Right an amount equal to the applicable hourly Marginal Congestion Component multiplied by the specified MWs. In each instance when the applicable Marginal Congestion Component is negative, the Independent Transmission Provider shall charge to each Primary Holder of an Obligation Right (but not the Primary Holder of an Option Right) an amount equal to the absolute value of the applicable Marginal Congestion Component multiplied by the specified MWs.

3.5.2 Settlement of Flowgate Rights: For each hour in the Day-Ahead Market, the Independent Transmission Provider shall determine, consistent with the provisions in Section F.3.4, the Flowgate LMP in each direction associated with each Flowgate on the transmission system operated by the Independent Transmission Provider.

(i) Holders of Flowgate Rights. For each hour of the Day-Ahead Market, the Independent Transmission Provider shall pay each Primary Holder of a Flowgate Right an amount equal to the applicable hourly Flowgate LMP multiplied by the MWs specified in the Primary Holder's Flowgate Right.

3.6 Disposition of Congestion Revenue Surplus or Deficit

3.6.1 Hourly Congestion Charge Collection: The Hourly Congestion Charge Collection is defined here as the sum of the Hourly Energy Congestion Charge Collection plus the Hourly Transmission Congestion Charge Collection. The Hourly Energy Congestion Charge Collection is defined for any hour of the Day-Ahead Market as (i) the net amounts charged to purchasers of Energy in the Independent Transmission Provider's Day-Ahead Market associated with the Marginal Congestion Component of the hourly LMPs at the purchasers' buses, less (ii) the net amounts paid to sellers of Energy in the Independent Transmission Provider's Day-Ahead Market associated with the Marginal Congestion Component of the hourly LMPs at the sellers' buses. The Hourly Transmission Congestion Charge Collection is defined for any hour of the Day-Ahead Market as the net amounts charged to Customers for Transmission Service scheduled in the Day-Ahead Market associated with the Marginal Congestion Component of the applicable hourly Transmission Usage Charges.

3.6.2 Hourly Net Congestion Revenue Owed to Congestion Revenue Rights Holders: The Hourly Net Congestion Revenue owed to Congestion Revenue Rights Holders for any hour in the Day-Ahead Market is defined here as the net hourly amounts payable to Primary Congestion Revenue Rights Holders pursuant to Sections F.3.5.1 and F.3.5.2.

3.6.3 Determination and Disposition of Congestion Revenue Surplus or Deficit: For each hour of the Day-Ahead Market, the Independent Transmission Provider shall calculate the Hourly Congestion Charge Collection and the Hourly Net Congestion Revenue Owed to Congestion Revenue Rights

Holders. For each hour of the Day-Ahead Market where the Hourly Congestion Charge Collection exceeds the Hourly Net Congestion Revenue Owned to Congestion Revenue Rights Holders, the Independent Transmission Provider shall allocate the revenue surplus to the Transmission Owners. For each hour of the Day-Ahead Market where the Hourly Congestion Charge Collection is less than the Hourly Net Congestion Revenue Owned to Congestion Revenue Rights Holders, the Independent Transmission Provider shall charge the revenue deficit to the Transmission Owners.

3.7 Disposition of Marginal Loss Revenue Surplus

3.7.1 Hourly Marginal Loss Charge Collection: The Hourly Marginal Loss Charge Collection is defined here as the sum of the Hourly Energy Marginal Loss Charge Collection plus the Hourly Transmission Marginal Loss Charge Collection. The Hourly Energy Marginal Loss Charge Collection is defined for any hour of the Day-Ahead Market as (i) the net amounts charged to purchasers of Energy in the Independent Transmission Provider's Day-Ahead Market associated with the Marginal Losses Component of the hourly LMPs at the purchasers' buses, less (ii) the net amounts paid to sellers of Energy in the Independent Transmission Provider's Day-Ahead Market associated with the Marginal Losses Component of the hourly LMPs at the sellers' buses. The Hourly Transmission Marginal Loss Charge Collection is defined for any hour of the Day-Ahead Market as the net amounts charged to Customers for Transmission Service scheduled in the Day-Ahead Market associated with the Marginal Cost Component of the applicable hourly Transmission Usage Charges.

3.7.2 Determination and Disposition of Marginal Loss Revenue Surplus: For each hour of the Day-Ahead Market, the Independent Transmission Provider shall calculate the Hourly Marginal Loss Charge Collection and the Hourly Net Energy Revenue Owed to Generators for losses associated with all Transactions. For each hour of the Day-Ahead Market where the Hourly Marginal Loss Charge Collection exceeds the Hourly Net Energy Revenue Owed to Generators for Losses associated with all Transactions, the Independent Transmission Provider shall allocate the revenue surplus to reduction in the charge for Network Access Service. [The Independent Transmission Provider shall determine the exact allocation to each Customer and will file procedures for determining the allocation of the revenue surplus to each Customer.]

4. Day-Ahead Market for Regulation and Frequency Response

4.1 General: The Day-Ahead Market for Regulation establishes clearing prices and settlement rules for Suppliers that have offered eligible Regulation capacity to the market. The Transmission Provider shall procure Regulation through this market on behalf of Load-Serving Entities that have chosen not to Self-supply or purchase through bilateral contracts. Both Generation and Load may Bid to provide Regulation in the Day-Ahead Market if they meet the criteria for eligibility.

4.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (vii) for the Day-Ahead Market for Regulation. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Regulation criteria and requirements in accord with regional or local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS a Total Regulation Requirement for the Independent Transmission Provider's Service Area for each hour of the Operating Day. This hourly requirement enters the Day-Ahead Security Constrained Unit Commitment. The Total Regulation Requirement may be subdivided into locational Regulation Requirements; that is, those assigned to specific locations (or Zones) within the Service Area.

(iii) Allocate the obligation for meeting the Total Regulation Requirement among Load-Serving Entities. The obligation of each Load-Serving Entity in any hour shall be equal to the product of (1) the Load-Serving Entity's Real-Time load in the hour as a percentage of the total Real-Time load in the Independent Transmission Provider's Service Area in the hour and (2) the total Day-Ahead Total Regulation Requirement for the hour. The Load-Serving entity's forecasted Regulation obligation for purposes of Section F.2.8.1(iii) shall be equal to the product of (1) the Load-Serving Entity's Day-Ahead scheduled load in an hour and (2) the total Day-Ahead Regulation requirement in the hour.

(iv) Establish and post on its OASIS rules for eligibility to supply Regulation in the Day-Ahead Market that are consistent with this Tariff, including minimum technical requirements and performance standards for a Generator or Load to provide Regulation in response to signals sent by the Independent Transmission Provider.

(v) Establish and post on its OASIS the Bid data requirements and rules for self-scheduling and Bidding, and provide the market functions required for determination of hourly Day-Ahead Spinning Regulation Market Clearing Prices and selection of Day-Ahead Regulation Market Suppliers. Establish and post on its OASIS how these pricing and selection rules are modified to account for locational Regulation requirements. Establish how these pricing and selection rules are modified in the event of shortages in Bid-in Regulation capacity. [The Independent Transmission Provider shall include procedures for self-supply.]

(vi) Establish and post on its OASIS the rules for determination of any additional payments necessary to support efficient operations of the Day-Ahead Regulation Market and the efficient joint operation of the Day-Ahead Market for Regulation and other Day-Ahead Markets.

(vi) Provide the Settlement functions associated with purchase and sale of Regulation in the Day-Ahead Market.

(vii) Post the Day-Ahead Regulation Market Clearing Prices.

4.3 Purchaser Rules and Obligations: The Purchaser of Regulation Service has the obligations and rights set forth in (i) through (iv):

(i) Each Load-Serving Entity is required to fulfill its Operating Day Regulation obligation on the basis of either or both Self-Supply or procurement from the Day-Ahead and Real-Time markets for Regulation. The Transmission Provider shall procure Regulation Reserve on behalf of Load-Serving Entities and determine the final cost of each MW purchased.

(ii) A Load-Serving entity may meet its Regulation obligation through Self-Supply by offering into the Day-Ahead Market for Regulation its own Resources capable of supplying Regulation or Resources for which it has made contractual arrangements with third parties able to provide Regulation on a comparable basis. Such self-supplied Resources must be placed under the Independent Transmission Provider's control, and must meet the Independent Transmission Provider's rules for eligibility to supply Regulation (see Section 5.2 and 5.4.1). These self-supplied Resources are scheduled in the Day-Ahead Market for Regulation at a Supply Bid Price of $0/MWh. Also, a Load-Serving Entity shall be paid the applicable Day-Ahead Market Clearing Price for any Regulation self-supplied in excess of its obligation.

(iii) A Load-Serving Entity that has not fulfilled all of its Regulation obligation through Self-Supply is required to allow the Independent Transmission Provider to procure sufficient Regulation that it has not self-supplied through the Day-Ahead, and if necessary, the Real-Time Regulation Market to fulfill the obligation that is not self-supplied.

4.4 Supplier Rules and Obligations

4.4.1 Eligibility to Supply: To be eligible to supply Regulation in the Day-Ahead Market for Regulation, a Supplier or a Generator contracted by a Supplier must meet criteria (i) to (v), as follow.

(i) Suppliers of Regulation may use only Generators and/or Load that are electrically within the Independent Transmission Provider's Service Area.

(ii) Suppliers of Regulation may use only Generators and/or Load that are able to respond to AGC Base Point Signals sent by the Independent Transmission Provider pursuant to the Independent Transmission Provider procedures.

(iii) Suppliers of Regulation may use only Generators and/or Load that meet Independent Transmission Provider standards for Generator or Load performance.

(iv) Suppliers of Regulation shall not use, contract to provide, or otherwise commit the capability that is designated to provide Regulation to provide Energy or Spinning Reserve to any party other than the Independent Transmission Provider.

(v) Suppliers of Regulation shall provide the Bid information specified in Section F.4.4.2.

4.4.2 Specification of Bids: Suppliers of Regulation must provide the Bid information in (i) to (vii), as follows.

(i) Availability Bid price ($/MWh).

(ii) Regulation Capability (MW) of the Generator supplying Regulation.

(iii) Response Rate (MW/Minute) of the Generator supplying Regulation.

(iv) Upper and Lower Regulation Limits (MW).

(v) Hours of availability to provide Regulation.

(vi) Any additional physical data required by the Independent Transmission Provider

(vii) Location of Resources

4.5 Calculation of Market Clearing Price: The Independent Transmission Provider shall calculate a Market Clearing Price for the Day Ahead Market for Regulation, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Regulation Price for each Supplier based on the sum of the Supplier's Availability Bid and its Day-Ahead Unit-Specific Opportunity Cost (as defined below). The hourly Day-Ahead Regulation Market Clearing Price shall be the higher of (i) the highest Supplier Regulation Price needed to meet the Independent Transmission Provider's Regulation Requirement for each hour of the Next Day, or (ii) the highest Market Clearing Price in the hour for Operating Reserves.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Regulation each hour shall be equal to the product of:

(i) the deviation of the Regulation set point of the Generator that is required in order to provide Regulation from the Resource's expected output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the greater of (a) the $/MWh difference between the expected Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Regulation set point for the Resource) in the Real-Time Energy Market and (b) zero.

4.6 Calculation of Additional Payments and Charges

4.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate for each Resource scheduled for Regulation in the Day-Ahead Market the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section F.1.11.

4.6.2 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Day-Ahead Market for Regulation.]

4.7 Market Rules for Shortages

(i) [The Independent Transmission Provider may include in this section market rules, including calculation of market prices and determination of out of market payments, in the event of a shortfall in Regulation in the Day-Ahead Market due to a shortage of available capacity. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) [The Independent Transmission Provider may include in this section procedures for soliciting additional Bids for Regulation in the event that Bids and self-supplied provision of Regulation submitted in the Day-Ahead Markets fall short of the Regulation Requirement for the Operating Day.

4.8 Settlement: The Independent Transmission Provider will provide timely settlement of sales of Regulation in the Day-Ahead Market for Regulation pursuant to Section 4.8.1.

4.8.1 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier, the hourly Day-Ahead Market Clearing Price for Regulation times the Quantity (MW) of the Supplier's Regulation scheduled (*i.e.*, selected) in the hour.

5. Day-Ahead Market for Operating Reserve—Spinning Reserve

5.1 General: The Independent Transmission Provider shall establish bid-based markets for the types of Operating Reserve—Spinning Reserves (*e.g.*, 10-minute, 30-minute) necessary to meet local reliability authority rules or NERC guidelines. Day-Ahead Markets for Spinning Reserve shall be used to provide clearing prices and settlement rules for Suppliers of Spinning Reserve that have offered eligible Spinning Reserve capacity to the market. The Transmission Provider shall procure Spinning Reserves in this market on behalf of Purchasers of Spinning Reserve that have chosen not to self-supply or procure through bilateral contracts. Both Generation and Load may Bid to provide Spinning Reserve in the Day-Ahead Market if they meet criteria for eligibility.

5.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (vii) for the Day-Ahead Market for Spinning Reserve. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Spinning Reserve criteria and requirements in accord with regional or local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS a Total Spinning Reserve Requirement for the Independent Transmission Provider's Service Area for each hour of the Operating Day. This hourly requirement enters the Day-Ahead Security Constrained Unit Commitment. The Total Spinning Reserve Requirement may be sub-divided into locational Spinning Reserve Requirements; that is, assigned to specific locations (or Zones) within the Service Area.

(iii) Allocate the obligation for meeting the Total Spinning Reserve Requirement among Load-Serving Entities. The obligation of each Load-Serving Entity in any hour shall be equal to the product of (1) the Load-Serving Entity's Real-Time load in the hour as a percentage of the total Real-Time load in the Independent Transmission Provider's Service Area in the hour and (2) the total Day-Ahead Total Spinning Reserve Requirement for the hour. The Load-Serving Entity's forecasted Spinning Requirement obligation for purposes of Section F.2.8.1(iii) shall be equal to (1) the Load-Serving Entity's Day-Ahead scheduled load in an hour multiplied by (2) the total Day-Ahead Spinning Reserve requirement in the hour.

(iv) Establish and post on its OASIS rules for eligibility to supply Spinning Reserve in the Day-Ahead Market that are consistent with this Tariff, including minimum technical requirements and performance standards for a Generator or Load to provide Spinning Reserve.

(v) Establish and post on its OASIS the Bid data requirements and rules for self-scheduling and Bidding that are consistent with this Tariff, and provide the market functions required for determination of hourly Day-Ahead Spinning Reserve Market Clearing Prices and selection of Day-Ahead Spinning Reserve Market Suppliers. Establish how these pricing and selection rules are modified to account for locational Spinning Reserve requirements. Establish how these pricing and selection rules are modified in the event of shortages in Bid-in Spinning Reserve capacity.

(vi) Establish and post on its OASIS the rules for determination of any additional payments necessary to support efficient operations of the Day-Ahead Market for Spinning Reserve and the efficient joint operation of the Day-Ahead Market for Spinning Reserve and other Day-Ahead Markets.

(vii) Provide the Settlement functions associated with sale of Spinning Reserve in the Day-Ahead Market.

(vii) Post the Day-Ahead Market Clearing Prices for Spinning Reserve.

5.3 Purchaser Rules and Obligations

(i) Each Load-Serving Entity is required to fulfill its Operating Day Spinning Reserve obligation on the basis of either or both self-supply or procurement from the Day-Ahead and Real-Time markets for Spinning Reserve. The Independent Transmission Provider shall procure Spinning Reserve on behalf of Load-Serving Entities and determine the final cost of each MW purchased.

(ii) A Load-Serving Entity may meets its Spinning Reserve obligation through Self-Supply by offering its own Resources capable of supplying Spinning Reserves or Resources for which it has made contractual arrangements with third parties able to provide Spinning Reserves on a comparable basis. Such self-supplied Resources must be placed under the Independent Transmission Provider's control, and must meet the Independent Transmission Provider's rules for eligibility (see Section 5.2 and 5.4.1). These self-supplied Resources are scheduled in the Day-Ahead Spinning Reserves Market. A Load-Serving Entity shall be paid the applicable Day-Ahead Market clearing price for any Spinning Reserve self-supplied in excess of its obligation.

(iii) A Load-Serving Entity that has not fulfilled all of its Spinning Reserve obligation through Self-Supply is required to allow the Independent Transmission Provider to procure sufficient Spinning Reserve that it has not Self-Supplied through the Day-Ahead and, if necessary, Real-Time Spinning Reserve market to fulfill the obligation that is not Self-Supplied.

5.4 Supplier Rules and Obligations

5.4.1 Eligibility to Supply: To be eligible to supply Spinning Reserve in the Day-Ahead Market for Spinning Reserve, a Supplier or a Generator contracted by a Supplier must meet criteria (i) to (iv), as follow.

(i) Suppliers of Spinning Reserve may use only Generators and/or Load that are electrically within the Independent Transmission Provider's Service Area.

(ii) Suppliers of Spinning Reserve may use only Generators and/or Load that meet Independent Transmission Provider standards for Generator performance; similarly, Demand Resources must meet Independent Transmission Provider standards for response capability.

(iii) Suppliers of Spinning Reserve shall not use, contract to provide, or otherwise commit the capability that is designated to provide Spinning Reserve to provide Energy, Regulation or Supplemental Reserve to any party other than the Independent Transmission Provider.

(iv) Suppliers of Spinning Reserve shall provide the Bid information specified in Section 5.4.2.

5.4.2 Specification of Bids: Suppliers of Spinning Reserve must provide the Bid information in (i) to (vi), as follows.

(i) Availability Bid price ($/MWh).

(ii) Response Rate (MW/Minute) of the Generator supplying Spinning Reserve.

(iii) Hours of availability to provide Spinning Reserve.

(iv) Any additional physical data required by the Independent Transmission Provider.

(v) Location of Resource.

5.5 Calculation of Market Clearing Price

5.5.1 Methodology for Calculation of Clearing Price: The Independent Transmission Provider shall calculate a Market Clearing Price for the Day Ahead Market for Spinning Reserve, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Spinning Reserve Price for each Supplier based on the sum of the Supplier's Availability Bid and its Day-Ahead Unit-Specific Opportunity Cost (as defined below). The hourly Day-Ahead Spinning Reserve Market Clearing Price shall be the higher of (i) the highest Supplier Spinning Reserve Price needed to meet the Independent Transmission Provider's Spinning Reserve Requirement for each hour of the Next Day, or (ii) the highest Market Clearing Price in the hour for Supplemental Reserves.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Spinning Reserve each hour shall be equal to the product of:

(i) the deviation of the set point (MWh) of the Generator that is required in order to provide Spinning Reserve from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the greater of (a) the $/MWh difference between the Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Spinning Reserve set point for the Resource) in the Day-Ahead Energy Market and (b) zero.

5.5.2 Calculation of Zonal or Locational Prices: Separate Day-Ahead Spinning Reserve Market Clearing Prices will be calculated for Spinning Reserve located in each distinct Reserve Location for which there is a separate Spinning Reserve requirement. When there are no binding transmission constraints between Reserve Locations, the Day-Ahead Ancillary Price for Spinning Reserve shall be the same in each of the locations.

5.5.3 Transmission for Operating Reserves: A Supplier located outside of a particular Reserve Location may provide Spinning Reserves if the necessary transmission arrangements to deliver Energy from the Supplier's capacity to the Reserve Location are made. The cost of any transmission service would have to be included in evaluating the total cost of Operating Reserves.

5.6 Calculation of Additional Payments and Charges

5.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate, for each Resource scheduled for Spinning Reserve in the Day-Ahead Market the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section F.1.11.

5.6.2 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Day-Ahead Markets for Spinning Reserves.]

5.7 Market Rules for Shortages

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities, calculation of market prices, and determination of out of market payments in the event of a shortfall in the required system requirements for Spinning Reserves due to a shortage of available capacity. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) [The Independent Transmission Provider may include in this section procedures for soliciting additional Bids for Spinning Reserves in the event that Bids and self-supplied provision of Spinning Reserves submitted in the Day-Ahead Markets fall short of the required system requirements for Spinning Reserves.]

5.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases and sales of Spinning Reserve in the Day-Ahead Market for Spinning Reserve pursuant to Sections 5.8.1.

5.8.1 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier the hourly Day-Ahead Spinning Reserve Market Clearing Price times the quantity (MW) of the Supplier's Spinning Reserve capability provided in the hour.

6. Day-Ahead Markets for Operating Reserve-Supplemental Reserve

6.1 General: The Independent Transmission Provider shall establish the types of Supplemental Reserves (*e.g.*, 10-minute, 30-minute, 60-minute) necessary to meet local reliability authority rules and NERC guidelines. Day-Ahead Markets for Supplemental Reserves establish clearing prices and settlement rules for Suppliers of Supplemental that have offered eligible Supplemental Reserve capacity to the market. The Transmission Provider shall procure Supplemental Reserves in this market on behalf of Purchasers of Supplemental Reserves that have chosen not to Self-supply or procure through bilateral contracts. Both Generation and Load may Bid to provide Supplemental Reserves in the Day-Ahead Market if they meet criteria for eligibility.

6.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (viii) for the Day-Ahead Markets for Supplemental Reserves. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Supplemental Reserve criteria and requirements in accord with regional or local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS Total Supplemental Reserves Requirements for the Independent Transmission Provider's Service Area for each Hour of the Operating Day. This hourly requirement enters the Day-Ahead Security Constrained Unit Commitment. The Total Supplemental Reserve Requirements may be subdivided into locational Supplemental Reserve Requirements; that is, assigned to specific locations (or zones) within the Service Area.

(iii) Allocate the obligation for meeting the Total Supplemental Reserve Requirement among Load-Serving Entities. The obligation of each Load-Serving Entity in any hour shall be equal to the product of (1) the Load-Serving Entity's Real-Time load in the hour as a percentage of the total Real-Time load in the Independent Transmission Provider's Service Area in the hour and (2) the Total Day-Ahead Total Supplemental Reserve Requirement for the hour. The Load-Serving Entity's forecasted Supplemental Reserve obligation for purposes of Section F.2.8.1 (iii) shall be equal to the product of (1) the Load-Serving Entity's Day-Ahead scheduled load in the hour as a percent of the total Day-Ahead load in the Independent Transmission Provider's Service Area in the hour and (2) the Total Day-Ahead Supplemental Reserve Requirement in the hour.

(iv) Establish and post on its OASIS rules for eligibility to supply Supplemental Reserves in the Day-Ahead Market that are consistent with this Tariff, including minimum technical requirements and performance standards for a Generator and/or Load to provide Supplemental Reserves.

(v) Establish and post on its OASIS the Bid data requirements and rules for self-scheduling and Bidding that are consistent with this Tariff, and provide the market functions required for determination of hourly Day-Ahead Supplemental Reserves Market Clearing Prices and selection of Day-Ahead Supplemental Reserves Market Suppliers. Establish how these pricing and selection rules are modified to account for locational Supplemental Reserves requirements. Establish how these pricing and selection rules are modified in the event of a shortage of Bid-in Supplemental Reserve capacity.

(vi) Provide the Settlement functions associated with purchase and sale of Supplemental Reserves in the Day-Ahead Market.

(vii) Post the Day-Ahead Supplemental Reserves Market Clearing Prices.

6.3 Purchaser Rules and Obligations:

(i) Each Load-Serving Entity is required to fulfill its Operating Day Supplemental Reserves obligation on the basis of either or both Self-Supply or procurement from the Day-Ahead and Real-Time markets for Supplemental Reserves. The Independent Transmission Provider shall procure Supplemental Reserve on behalf of Load-Serving Entities and determine the final cost of each MW purchased.

(ii) A Load-Serving Entity may meet its Supplemental Reserve obligation through Self-Supply by offering into the Day-Ahead Market for Supplemental Reserves its own Resources capable of supplying Supplemental Reserves or Resources for which it has made contractual arrangements with third parties able to provide Supplemental Reserves on a comparable basis. Such self-supplied Resources must be placed under the Independent Transmission Provider's control, and must meet the Independent Transmission Provider's rules for eligibility (see Sections 6.2 and 6.4.1). These self-supplied Resources are scheduled in the Day-Ahead Reserves Market. A Load-Serving Entity shall be paid the applicable Day-Ahead Market clearing price for any Supplemental Reserve self-supplied in excess of its obligation.

(iii) A Load-Serving Entity that has not fulfilled all of its Supplemental Reserves obligation through self-supply is required to allow the Independent Transmission Provider to procure sufficient Supplemental Reserves that it has not Self-Supplied through the Day-Ahead and, if necessary, Real-Time Supplemental Reserves market to fulfill the obligation that is not Self-Supplied.

6.4 Supplier Rules and Obligations

6.4.1 Eligibility to Supply: To be eligible to supply Supplemental Reserves in the Day-Ahead Markets for Supplemental Reserve, a Supplier or a Generator contracted by a Supplier must meet criteria (i) to (iv), as follow.

(i) Subject to Independent Transmission Provider requirements, Suppliers of Supplemental Reserves may use Generators and/or Load that are electrically within or outside the Independent Transmission Provider's Service Area.

(ii) Suppliers of Supplemental Reserves may use only Generators and/or Load that meet Independent Transmission Provider standards for Generator performance.

(iii) Suppliers of Supplemental Reserves shall not use, contract to provide, or otherwise commit the capability that is designated to provide Supplemental Reserves to provide Energy, Regulation and Frequency Response, or Spinning Reserve to any party other than the Independent Transmission Provider.

(iv) Suppliers of Supplemental Reserves shall provide the Bid information specified in Section 4.2.

6.4.2 Specification of Bids: Suppliers of Supplemental Reserves must provide the Bid information in (i) to (iv), as follows.

(i) Availability Bid price ($/MWh).

(ii) Response Rate (MW/Minute) of the Resource supplying Supplemental Reserve.

(iii) Hours of availability to provide Supplemental Reserve.

(iv) Any additional physical data required by the Independent Transmission Provider.

(v) Location of Resource.

6.5 Calculation of Market Clearing Prices for Supplemental Reserves

6.5.1 Methodology for Calculation of Prices: The Independent Transmission Provider shall calculate a Market Clearing Price for each Day-Ahead Market for Supplemental Reserves, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Estimated Supplemental Reserve Price for each Supplier based on the sum of the Supplier's Availability Bid and its Day-Ahead Unit-Specific Opportunity Cost (as defined below). The hourly Day-Ahead Supplemental Reserve Market Clearing Price shall be the higher of (i) the highest Supplier Supplemental Reserve Price needed to meet the Independent Transmission Provider's Supplemental Reserve Requirement for each hour of the Next Day, or (ii) the Market Clearing Price in the hour for a lower quality Supplemental Reserve.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Supplemental Reserves each hour shall be equal to the product of:

(i) the deviation of the set point (MWh) of the Generator that is expected to be required in order to provide Supplemental Reserve from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the absolute value of the difference between the Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Supplemental Reserve set point for the Resource) in the Day-Ahead Energy Market.

6.5.2 Calculation of Zonal or Locational Prices: Separate Day-Ahead Supplemental Reserve Market Clearing Prices will be calculated for Supplemental Reserve located in each distinct Reserve Location for which there is a separate Supplemental Reserve requirement. When there are no binding transmission constraints between Reserve Locations, the Day-Ahead Ancillary Price for Supplemental Reserve shall be the same in each of the locations.

6.5.3 Transmission for Operating Reserves: A Supplier located outside of a particular Reserve Location may provide 10-Minute Supplemental Reserve if the necessary arrangements Energy from the Supplier's capacity to the Reserve Location are made. The cost of any transmission service would have to be included in evaluating the total cost of Operating Reserves.

6.6 Calculation of Additional Payments and Charges

6.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate, for each Resource scheduled for Supplemental Reserves in the Day-Ahead Market the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section F.1.11.

6.6.2 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Day-Ahead Markets for Supplemental Reserves.]

6.7 Market Rules for Shortages

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities of Supplemental Reserve purchased, calculation of market prices, and determination of out-of-market payments in the event of a shortfall in the required system requirements for Supplemental Reserves due to a shortage of available capacity. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) [The Independent Transmission Provider may include in this section procedures for soliciting additional Bids for Supplemental Reserves in the event that Bids and self-supplied provision of Supplemental Reserves submitted in the Day-Ahead Markets fall short of the required system requirements for Supplemental Reserves.]

6.8 Settlement: The Independent Transmission Provider will provide timely settlement of sales of Supplemental Reserves in the Day-Ahead Markets for Supplemental Reserves pursuant to Sections 6.8.1.

6.8.1 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier the hourly Day-Ahead Supplemental Reserve Market Clearing Price times the quantity (MW) of the Supplier's Supplemental Reserve capability provided in the hour.

G. Post-Day-Ahead Scheduling and Real-Time Markets

Preamble

The Independent Transmission Provider will operate a Real-Time Market in order to develop a post Day-Ahead Schedule and Real Time Dispatch Schedule for Transmission Service, Energy, and Ancillary Services. The Real-Time Schedule will be developed so as to maximize the combined economic value of transmission service, Energy, and Ancillary Services, based on the Bids submitted.

1. Post-Day-Ahead Bidding and Scheduling Procedures

1.1 General: The Independent Transmission Provider shall establish procedures for modification of the Day-Ahead Schedule and development of the Real-Time Schedule and dispatch that incorporate components (i) to (vi), as follow.

(i) The Independent Transmission Provider will allow Market Participants that have had selected in the Day-Ahead Schedule (1) a Quantity of Energy, whether a purchase or sale, Regulation or Operating Reserve, (2) a Bilateral Transaction, or (3) a Self-Schedule or Self-Supply, to change the Quantities in the Schedule at any time following the close of the Day-Ahead Market but before the [Scheduling Deadline to be provided by the Independent Transmission Provider] prior to each Dispatch Hour in the Operating Day.

(ii) The Independent Transmission Provider will allow Suppliers or Purchasers of Energy and Suppliers of Regulation or

Operating Reserves that have capacity not selected in the Day-Ahead Schedule to submit new Bids, including Prices ($/MW) and Quantities (MW), into the Real-Time Market. [Independent Transmission Provider will provide schedule.]

(iii) The Independent Transmission Provider will allow Market Participants to submit new Bilateral Transactions and Self-Schedules at any time following the close of the Day-Ahead Market but before the [Scheduling Deadline to be provided by the Independent Transmission Provider] prior to each Dispatch Hour in the Operating Day.

(iv) The Independent Transmission Provider will post on its OASIS the Deadlines for Scheduling Revised or New Quantities and for submission of Price Bids into the Real-Time Market, consistent with the Tariff.

(v) The Independent Transmission Provider shall establish scheduling procedures for External Transactions during each Hour and Quarter-Hour of the Operating Day, consistent with the requirements established by the Commission.

(vi) A Supplier or Purchaser in the Real-Time Market, as well as a Bilateral Schedule or Self-Schedule that submits a Price Bid, that follows Independent Transmission Provider Dispatch Instructions that deviate from the previously selected schedules submitted by the Supplier or Purchaser in the Day-Ahead Market, shall be provided with a Bid Revenue Sufficiency Guarantee, pursuant to Section G.2.3.

1.2 Rules for Self Schedules

1.2.1 Supplier-Committed Self Schedules

(i) Suppliers that wish to increase the amount of Energy scheduled above the amounts scheduled in the Day-Ahead Market, regardless of the applicable Real-Time Energy LMP, may so inform the Independent Transmission Provider [before the scheduling deadline provided by the Independent Transmission Provider] prior to each Dispatch Hour in the Operating Day.

(ii) Such Suppliers of Energy are required to submit a MW quantity and a location.

1.3 Rules for Bilateral Transactions

1.3.1 Internal Transactions

(i) All Internal Transactions submitted or modified after the Day-Ahead Schedule must specify a Receipt Point, a Delivery Point, a MW quantity injected at the Receipt Point and a MW quantity withdrawn at the Delivery Point.

(ii) Internal Transactions may voluntarily submit a Price Bid ($/MW) over some or all of the MW range which indicates the Customer's willingness to reduce or eliminate the Transaction in the next Security Constrained Dispatch time period at the Independent Transmission Provider's instruction when the applicable Real-Time Transmission Usage Charge reaches or exceeds the price Bid.

(iii) Internal Transactions may voluntarily submit a Decremental Energy Bid (in $/MW) over some or all of the MW range, which indicates the Customer's willingness to reduce the amount of Energy supplied at the Receipt Point at the Independent Transmission Provider's instruction (while retaining the amount of Energy withdrawn at the Delivery Point) when the Real-Time Energy LMP at the Receipt Point falls below the Decremental Energy Bid.

1.3.2 External Transactions

(i) All External Transactions submitted or modified after the Day-Ahead Schedule must specify a Receipt Point, a Delivery Point, a MW quantity injected at the Receipt Point and a MW quantity withdrawn at the Delivery Point. Either the Receipt Point or the Delivery Point must be a point at the boundary of the Independent Transmission Provider Service Area. All External Transactions must specify a minimum run time.

(ii) The Independent Transmission Provider shall offer Market Participants with External Transactions submitted after the Day-Ahead Schedule or modifying the Day-Ahead Schedule two options for scheduling. (1) External Transactions can be scheduled without a Price Bid. (2) External Transactions can be scheduled with a Price Bid ($/MW) over some or all of the MW quantity being scheduled.

(iii) External Transactions that are Exports may voluntarily submit a Decremental Energy Bid (in $/MW) over some or all of the MW range, which indicates the Customer's willingness to reduce the amount of Energy supplied at the Receipt Point at the Independent Transmission Provider's instruction (while retaining the amount of Energy withdrawn at the Delivery Point) when the Real-Time Energy LMP at the Receipt Point falls below the Decremental Energy Bid. External Transactions that are imports may voluntarily submit an Incremental Energy Bid (in $/MW) over some or all of the MW range, which indicates the Customer's willingness to reduce the amount of Energy withdrawn at the Delivery Point at the Independent Transmission Provider's instruction (while retaining the amount of Energy injected at the Receipt Point) when the Real-Time Energy LMP at the Delivery Point rises above the Incremental Energy Bid.

(iv) The Independent Transmission Provider will adjust External Transactions schedules on quarter hour notice.

(v) The Independent Transmission Provider shall accept Short Notice External Transactions (SNETs) following the Real-Time Trading Deadline up to some later SNET Deadline set by the Independent Transmission Provider. SNETs are not eligible to set Real-Time LMPs. SNETs have the lowest priority in the event of Curtailment of Customers.

1.4 Rules for Bidding: The Independent Transmission Provider shall evaluate accept all eligible Bids for Energy Supply and Demand, Regulation, and Operating Reserves. The requirements for Bid eligibility and the Bid Specifications are in Sections G 3.4, G.5.4 and G.7.4.

2. Security Constrained Intra-Day Unit Commitment and Dispatch

2.1 Intra-Day Security Constrained Unit Commitment: The Independent Transmission Provider may undertake a periodic intra-day Security-Constrained Unit Commitment for Resources with Start-up and No-load costs not committed in the Day-Ahead Schedule.

2.2 Security Constrained Dispatch: The Independent Transmission Provider shall run a Security Constrained Dispatch every five minutes to minimize the total Bid Production Costs of meeting the system Load and maintaining scheduled interchanges with adjacent Service Areas over the next Security Constrained Dispatch Interval. Bid Production Costs, for this purpose, will be calculated using selected Day-Ahead and Real-Time Bids for Energy and Ancillary Services submitted into the Real-Time Market. The Independent Transmission Provider shall dispatch the Power System consistent with the Bids that are submitted by Suppliers and accepted by the Independent Transmission Provider, while satisfying the actual system Load.

2.3 Intra-Day Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall ensure the minimum recovery of each Reserve's Bid prices for Resources scheduled after the close of the Day-Ahead Market, committed on an intra-day basis, or dispatched through the Real-Time Market.

(i) The Independent Transmission Provider shall determine, on a daily basis, if any Resource committed by the Independent Transmission Provider in the Real-Time Market will not recover its Start-Up, No Load and Energy Bid Price through revenues in the Real-Time Energy and Ancillary Services markets.

(ii) If the Start-Up and No Load Bids plus the net Energy and Ancillary Services Bid Price over the twenty-four (24) hour day of any Supply Resource scheduled, committed, or dispatched by the Independent Transmission Provider exceeds its Real-Time LMP revenue and Ancillary Service Revenue over the twenty-four (24) hour day, then that Supplier's Real-Time LMP revenue, the Real-Time Supply Bid Revenue Sufficiency Guarantee payment, shall be augmented by an additional payment in the amount of the shortfall. Resources not scheduled, committed, or dispatched by the Independent Transmission Provider, but which continue to operate shall not receive such a payment. This payment shall be supported through revenue collected from the Supply Bid Revenue Sufficiency Guarantee Charge.

(iii) If the total Real-Time Energy charges to any Demand Resource over the twenty-four (24) hour day exceeds its maximum willingness to pay, as reflected by the difference of its Real-Time Energy Bids and Start-up Cost Bid, the Demand Resource shall be augmented by a payment, the Demand Bid Revenue Sufficiency Guarantee Payment, in the amount of the overcharge. This payment is supported through revenues collected from the Demand Bid Revenue Sufficiency Guarantee Charge.

3. Real-Time Market for Energy

3.1 General: The Real-Time Market for Energy establishes clearing prices and settlement rules for Suppliers of Energy that have offered eligible Energy capacity to the market and for Purchasers of Energy that have chosen not to self-supply or procure through bilateral contracts.

3.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligations to provide services (i) to (v) for the Real-Time Market for

Energy. The rules governing these services are contained in this section.

(i) Establish and post on its OASIS rules that are consistent with this Tariff for eligibility to supply Energy in the Real-Time Market.

(ii) Establish and post on its OASIS the Bid data requirements and rules that are consistent with this Tariff and provide the market functions required for determination of hourly Real-Time Energy Market Clearing Prices and selection of Real-Time Energy Market Suppliers.

(iii) Establish and post on its OASIS the rules that are consistent with this Tariff for determination of any Additional Payments necessary to support efficient operations of the Real-Time Energy Market and/or the efficient operation of other Real-Time Markets.

(iv) Provide the Settlement functions associated with purchase and sale of Energy in the Real-Time Market.

(v) Post the Real-Time LMPs for Energy.

3.3 Purchaser Rules and Obligations

3.3.1 Specification of Bids. Bids to Purchase Energy in the Real-Time Market for Energy shall have the same price, quantity and data requirements as Bids to Purchase Energy in the Day-Ahead Market for Energy, as set forth in Section F.2.3.1. Virtual Demand Bids are not permitted in the Real-Time Market.

3.4 Supplier Rules and Obligations

3.4.1 Eligibility to Supply

(i) Suppliers of Real-Time Energy may not re-submit capacity selected for Energy in the Day-Ahead Market. Suppliers of Real-Time Energy may lower the Bid Price of capacity not selected for Energy in the Day-Ahead Market.

(ii) Suppliers of Real-Time Energy shall provide the Bid information specified in Section F.2.4.2.

3.4.2 Specification of Bids: Bids to Supply Energy in the Real-Time Energy Market, including Incremental and Decremental Energy, have the same price, quantity and data requirements as Bids to Supply Energy in the Day-Ahead Market for Energy, as set forth in Sections F.2.3 (b)–(d). Virtual Supply Bids are not permitted in the Real-Time Market.

3.4.3 Period of Bids to Supply Energy: Bids to Supply Incremental Energy or Decremental Energy pursuant to Sections F.3.4.1–3.4.2 can vary by price ($) and quantity (MW) in each Hour of the Real-Time Market.

3.5 Calculation of Real-Time Locational Marginal Prices for Energy

(i) Immediately in advance of each Security Constrained Dispatch Interval, the Independent Transmission Provider shall post the Real-Time Energy LMPs for each bus on its system that it estimates will clear the market and match Generation with Load during the upcoming Security Constrained Dispatch Interval, based on the Real-Time Bids submitted. These estimated Energy LMPs shall be called Ex Ante LMPs. The pricing calculations for each of these LMPs should be the same as those for the Day-Ahead Market, as set forth in Section F.2.4, with the modifications contained in this Section G.3.5.

(ii) Power system operations in the Real-Time Market, including, but not limited to, the determination of the least costly means of serving Load, depend upon the availability of a complete and consistent representation of Generator outputs, Loads, and power flows on the network. In calculating LMPs, the Independent Transmission Provider shall obtain a complete and consistent description of conditions on the electric network by using the most recent power flow solution produced by the Independent Transmission Provider's dispatch software and/or software that measures actual system conditions in Real-Time, such as a State Estimator.

3.5.1 Ex Post Energy LMP Calculation: At the close of each Security Constrained Dispatch Interval, the Independent Transmission Provider shall calculate Energy LMPs for each bus on its system that shall be used for settlement of the Real-Time Market. These LMPs shall be called Ex Post Energy LMPs. The Ex Post Energy LMP for a Security Constrained Dispatch Interval at a given bus shall be equal to the lower of (a) the Ex Ante Energy LMP for that bus; and (b) the marginal cost of making available to the bus the Energy actually produced during the Security Constrained Dispatch Interval by suppliers that submitted Real-Time Energy Bids.

3.5.2 Determination of Energy LMPs by Fixed Block Resources: In calculating LMPs in the Day-Ahead Market, the Bid of any Fixed Block Unit (*i.e.,* a unit whose output cannot be adjusted in increments as small as 1 MW) will not be considered in calculating the Day-Ahead LMP at any bus. In calculating LMPs in the Real-Time Market, the price Bid of a Fixed Block Unit may set LMP, but only when some portion of its Energy is necessary to meet Load, displace higher cost Energy, or satisfy Operating Reserves Requirements. The marginal cost of a Fixed Block Unit that forces more economic units to be backed down will not set Real-Time LMP unless needed to meet Load, displace higher price Energy or meet Reserves requirements. The marginal cost of a Fixed Block Unit will not set Real-Time LMP at any other time, including those times when it is scheduled solely to meet its minimum runtime requirements or because of inflexibilities in its operation.

3.5.3 Five Minute Real-Time LMPs: During the Operating Day, the LMP calculation shall be performed every [five minutes, or some other minute by minute interval determined by the system technology and software], using the Independent Transmission Provider's LMP methodology, producing a set of Real-Time Prices based on system conditions during the preceding interval.

3.6 Calculation of Additional Payments and Charges

3.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate, for each Resource scheduled, committed or dispatched for Energy in the Real-Time Market, the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section G.2.3.

3.6.2 Undergeneration by Suppliers

(i) [The Independent Transmission Provider may file to establish pricing rules, including market-based penalties, for Suppliers of Energy that persistently provide less Energy in Real-Time than instructed. One market-based penalty is to require the Supplier to buy Regulation at the Real-Time Market Clearing Price for Regulation in a quantity equivalent to the Energy not provided.]

(ii) [Exemptions: If the Independent Transmission Provider proposes penalties, suppliers, such as intermittants, that have constraints on following Dispatch Instructions or other operating limitations should be exempt from these penalties.]

(iii) Replacement Reserve Penalty [The Transmission Provider may file to establish market-based penalties for Suppliers of Regulation that provide less Regulation in Real-Time than instructed.]

3.6.3 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Real-Time Markets for Energy.]

3.7 Market Rules for Shortages or Emergencies

(i) [The Independent Transmission Provider may include in this section market rules, including calculation of market prices and determination of out-of-market payments, in the event of a shortfall in Energy in the Real-Time Market due to a shortage of available capacity or an Emergency. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) After the Day-Ahead Schedule is published, and up to a pre-specified period prior to each Dispatch Hour, the Independent Transmission Provider may, after giving notice to affected Resources, in order to prevent or address an Emergency, raise their Bid-in upper operating limits to their maximum and make the additional capacity available to the Scheduling for the Real-Time Market.

(iii) In the event of Emergency, Incremental Energy purchased above a Generator's Hourly Economic Maximum Level and up to the Generator's Hourly Emergency Maximum Level will be settled at the Real-Time LMPs. Decremental Energy purchased below the Hourly Economic Minimum Level and up to the Hourly Emergency Minimum Level will be settled at the higher of (1) the Bid Price for the Decremental Emergency Energy and (2) Real-Time LMPs.

3.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases and sales of Energy in the Real-Time Market for Energy pursuant to Sections G.3.7.1 and G.3.7.2.

3.8.1 Settlement when Actual Energy Injections are Less than Scheduled Energy Injections: When the actual Energy injections from a Supplier over a Security Constrained Dispatch Interval are less than its Energy scheduled in the Day-Ahead Market to be injected over that SCE interval, the Supplier shall pay for the difference in a charge equal to the product of: (a) the Real-Time Energy LMP calculated for that Security Constrained Dispatch Interval at the applicable Supplier's bus; and (b) the difference between the scheduled Energy injections and the actual Energy injections at that bus.

3.8.2 Settlement when Actual Energy Injections are Greater than Scheduled Energy Injections: When the actual Energy injections from a Supplier over a Security Constrained Dispatch Interval are greater than the Energy scheduled in the Day-Ahead Market to be injected over that Security Constrained Dispatch Interval, the Supplier shall be paid for the difference in a payment equal to the product of: (a) the Real-Time Energy LMP calculated for that Security Constrained Dispatch Interval at the applicable Supplier's bus; and (b) the difference between the actual Energy injections and the scheduled Energy injections at that bus.

3.8.3 Settlement when Actual Energy Withdrawals are Less than Scheduled Energy Withdrawals: When a Customer's actual Energy withdrawals over a Security Constrained Dispatch Interval are less than its Energy withdrawals scheduled in the Day-Ahead Market over that Security Constrained Dispatch Interval, the Customer shall be paid the product of: (a) the Real-Time Energy LMP calculated for that Security Constrained Dispatch Interval at the applicable Customer's bus (or at the Customer's zone, if the Customer elects to calculate and settle Energy purchases at Zonal-LMPs and meets the conditions specified in Section F.2.4(c)(ii)); and (b) the difference between the scheduled Energy withdrawals and the actual Energy withdrawals at that bus.

3.8.4 Settlement when Actual Energy Withdrawals are Greater than Scheduled Energy Withdrawals: When a Customer's actual Energy withdrawals over a Security Constrained Dispatch Interval are greater than its Energy withdrawals scheduled in the Day-Ahead Market over that Security Constrained Dispatch Interval, the Customer shall pay for the difference in a charge equal to the product of: (a) The Real-Time Energy LMP calculated for that Security Constrained Dispatch Interval at the applicable Customer's bus (or at the Customer's zone, if the Customer elects to calculate and settle Energy purchases at Zonal-LMPs and meets the conditions specified in Section F.2.4(c)(ii)); and (b) the difference between the actual Energy withdrawals and the scheduled Energy withdrawals at that bus.

4. Real-Time Scheduling for Transmission

4.1 General: As in the Day-Ahead Market, Real-Time Energy LMPs serve dual functions, providing (1) the prices for sales and purchases of Energy and (2) market-based prices for Congestion Management, including Congestion Charges to Bilateral Transactions, and Marginal Losses.

4.2 Transmission Bids: Customers may submit Bilateral Transaction Schedules that indicate whether or not they are willing to pay the Marginal Congestion Charge component of the Transmission Usage Charge. If the Bid indicates that the Customer is not willing to pay Congestion Charges, then the Bilateral Transaction will be scheduled only if there is no Marginal Congestion Charge in the Real-Time Market. If the Bid indicates that the Customer is willing to pay Congestion Charges, then the Bilateral Transaction will be scheduled regardless of the Marginal Congestion Charge in the Real-Time Market.

4.3 Real-Time Transmission Usage Charges

The Independent Transmission Provider shall charge a Transmission Usage Charge to all Bilateral Transactions whose transmission service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional transmission service after the determination of the Day-Ahead schedule. This charge is the product of (a) the amount of Energy scheduled (as of pre-determined trading deadline) to be withdrawn by that Customer in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Customer in that hour, in MWh; and (b) the Real-Time LMP at the Point of Delivery (which could be a Load Zone in which Energy is scheduled to be withdrawn or the external bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the Independent Transmission Provider Service Area), minus the Real-Time LMP at the Point of Receipt, in $/MWh. The Independent Transmission Provider shall divide each Transmission Usage Charge into separate components for Marginal Costs of Congestion and Marginal Costs of Losses.

4.3.1 Marginal Congestion Component: The Marginal Congestion Component of the Transmission Usage Charge shall be calculated as the Marginal Congestion Component of the Real-Time LMP at the Delivery Point minus the Marginal Congestion Component of the Real-Time LMP at the Receipt Point, as described in Section F.2.5(i).

4.3.2 Marginal Losses Component: The Marginal Losses Component of the Transmission Usage Charge shall be calculated as the Marginal Losses Component of the Real-Time LMP at the Delivery Point minus the Marginal Losses Component of the Real-Time LMP at the Receipt Point, as described in Section F.2.5(ii).

4.4 Calculation of Flowgate LMPs: The Independent Transmission Provider shall calculate and post Ex-Post Flowgate LMPs for the Real-Time Market.

4.5 Marginal Loss Charge Collection: The Real-Time Marginal Loss Charge Collection for any SCD interval is defined here as the sum of the Real-Time Energy Marginal Loss Charge Collection plus the Real-Time Transmission Marginal Loss Charge Collection for that SCD interval. The Real-Time Energy Marginal Loss Charge Collection is defined for any SCD interval of the Real-Time Market as (i) the sum of the net amounts associated with the Marginal Loss Component of the applicable Real-Time Energy LMP charged to: (a) each Supplier whose actual Energy injections over the SCD interval are less than its Energy scheduled in the Day-Ahead Market to be injected over that SCD interval and (b) each Purchaser whose actual Energy withdrawals over the SCD interval exceed its Energy scheduled in the Day-Ahead Market to be withdrawn over that SCD interval; less: (ii) the sum of the net amounts associated with the Marginal Loss Component of the applicable Real-Time Energy LMP paid to (c) each Supplier whose actual Energy injections over the SCD interval exceed its Energy scheduled in the Day-Ahead Market to be injected over that SCD interval and (d) each Purchaser whose actual Energy withdrawals over the SCD interval are less than its Energy scheduled in the Day-Ahead Market to be withdrawn over that SCD interval. The Real-Time Transmission Marginal Loss Charge Collection for any SCD interval is defined for any SCD interval of the Real-Time Market as the net amounts charged to Customers for Transmission Service scheduled in the Real-Time Market for the SCD interval associated with the Marginal Cost Component of the applicable hourly Transmission Usage Charges; less the net amounts associated with the Marginal Cost Component of the applicable hourly Transmission Usage Charges paid to Customers for Transmission Service scheduled in the Day-Ahead Market for reductions in Transmission Service in the Real-Time Market during the SCD interval.

4.5.1 Determination and Disposition of Marginal Loss Revenue Surplus: For each SCD interval of the Real-Time Market, the Independent Transmission Provider shall calculate the Marginal Loss Charge Collection and the Net Energy Revenue Owed to Generators for Losses associated with all Transactions. For each SCD interval of the Real-Time Market where the Marginal Loss Charge Collection exceeds the Net Energy Revenue Owed to Generators for Losses associated with all Transactions, the Independent Transmission Provider shall allocate the revenue surplus to reduction in the charge for Network Access Service. [The Independent Transmission Provider shall determine the exact allocation to each Customer and will file procedures for determining the allocation of the revenue surplus to each Customer.]

4.6 Disposition of Other Real-Time Revenue Surplus or Deficit: The Independent Transmission Provider shall calculate, for each Operating Day, the interval of the Real-Time Market, and the net revenue surplus or deficit from the operation of the Real-Time Market (defined as the difference between the revenues collected from all sources and all payment made to all sources, excluding the surplus for losses calculated pursuant to Section G.4.5). The Independent Transmission Provider shall allocate the revenue surplus or deficit for the Operating Day to the Transmission Owners. [The Independent Transmission Provider shall file procedures for determining the allocation of the surplus or deficit to Transmission Owners.]

5. Real-Time Market for Regulation

5.1 General: The Transmission Provider may require additional Regulation capability in response to system conditions in the Operating Day. The Real-Time Market for Regulation establishes clearing prices and settlement rules for eligible Suppliers of Regulation that have offered Regulation capacity following the close of the Day-Ahead Market. The Transmission Provider shall procure Regulation in this market on behalf of Purchasers who choose not to Self-supply or purchase through bilateral contracts. Both Generation and Load may to provide Regulation in the Real-Time Market if they meet criteria for eligibility.

5.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (viii) for the Real-Time Market for Regulation. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS criteria and requirements in accord with local reliability authority rules and NERC guidelines such that there is sufficient provision of Regulation in the Real-Time Dispatch.

(ii) Establish and post on its OASIS rules for eligibility to supply Regulation in the Real-Time Market.

(iii) Provide Base Point Signals to Generators providing Regulation to direct the Generator's output.

(iv) Establish and post on its OASIS the Bid data requirements and rules and provide the market functions required for determination of hourly Real-Time Regulation Market Clearing Prices and selection of Real-Time Regulation Market Suppliers. Establish how the pricing rules and selection procedures will be modified in the event of a shortage of Regulation capacity during the Operating Day.

(v) Monitor the Suppliers' performance to ensure that they provide Regulation Service as required.

(vi) Establish and post on its OASIS the rules for determination of any Additional Payments necessary to support efficient operations of the Real-Time Regulation Market and/or the efficient operation of other Real-Time Markets.

(vii) Provide the Settlement functions associated with purchase and sale of Regulation in the Real-Time Market.

(viii) Post the Real-Time Regulation Market Clearing Prices.

5.3 Purchaser Rules and Obligations

(i) Market Participants with a Regulation Requirement may fulfill their requirement by (1) self-scheduling an eligible Generator or Demand-Side Resource, (2) a bilateral contract with an eligible Supplier, or (3) purchasing from the Regulation Market.

(ii) Self-suppliers and purchasers of Regulation through Bilateral Contract must provide data on location and physical capabilities of the Generator or Supplier providing Regulation (see Section 4.2).

5.4 Supplier Rules and Obligations

5.4.1 Eligibility to Supply

(i) Suppliers of Regulation may only use Generators and/or Load that are electrically within the Independent Transmission Provider's Service Area.

(ii) Suppliers of Regulation may only use Generators and/or Load that are able to respond to AGC Base Point Signals sent by the Independent Transmission Provider pursuant to the Independent Transmission Provider Procedures.

(iii) Suppliers of Regulation may only use Generators and/or Load that meet Independent Transmission Provider standards for Generator performance.

(iv) Suppliers of Regulation shall not use, contract to provide, or otherwise commit the capability that is designated to provide Regulation to provide Energy or Spinning Reserve to any party other than the Independent Transmission Provider.

(v) Suppliers of Regulation shall provide the Bid information specified in Section 4.2.

(vi) Suppliers of Real-Time Regulation may not re-submit capacity selected for Energy in the Day-Ahead Market. Suppliers of Real-Time Regulation may lower the Bid Price of capacity selected for Energy in the Day-Ahead Market.

5.4.2 Specification of Bids

Suppliers of Regulation must provide the following Bid information:

(i) Availability Bid price ($/MWh).

(ii) Regulation Capability (MW) of the Generator supplying Regulation.

(iii) Response Rate (MW/Minute) of the Generator supplying Regulation.

(iv) Upper and Lower Regulation Limits (MW).

(v) Hours of availability to provide Regulation.

(vi) Any additional physical data required by the Independent Transmission Provider.

5.4.3 Bidding and Scheduling Process

(i) Bids rejected by the Independent Transmission Provider in the Day-Ahead Market may be modified and resubmitted into the Real-Time Market by the Supplier to the Independent Transmission Provider. [The Independent Transmission Provider Tariff will provide Procedures].

(ii) Bids in the Day-Ahead Market that are not accepted by the Independent Transmission Provider shall be automatically considered for the Real-Time Market, unless withdrawn by the Supplier.

(iii) If a Supplier reduces its available MW subsequent to being scheduled to provide Regulation or Operating Reserves (either Day-Ahead or in a Supplemental Commitment), and if it, as a result, can no longer provide both the amount of Energy it was scheduled to provide Day-Ahead and the amount of Regulation and Operating Reserves it was scheduled to provide, the Independent Transmission Provider will first reduce the amount of Operating Reserves it is scheduled to provide, and then will reduce the amount of Regulation it is scheduled to provide, until the total amount of Energy, Regulation and Operating Reserves it is scheduled to provide is equal to its available MW (or until it is no longer scheduled to provide Regulation or Operating Reserves).

5.5 Calculation of Market Clearing Price: The Independent Transmission Provider shall calculate a Market Clearing Price for the Real-Time Market for Regulation, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Regulation Price for each Supplier based on the sum of the Supplier's Availability Bid and its Real-Time Unit-Specific Opportunity Cost (as defined below). The Real-Time Regulation Market Clearing Price shall be the higher of (i) the highest Supplier Regulation Price needed to meet the Independent Transmission Provider's Regulation Requirement for each Dispatch Interval, or (ii) the highest Market Clearing Price in Dispatch Interval for Spinning Reserves or Supplemental Reserves.

The Unit-Specific Opportunity Costs of a Resource for bidding to sell Regulation shall be equal to the product of:

(i) the deviation of the Regulation set point of the Generator that is required to provide Regulation from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the greater of (a) the $/MWh difference between the Real-Time Energy LMP at the generation bus for the Resource and the Real-Time Bid price for Energy from the Resource (at the megawatt level of the Regulation set point for the Resource) in the Real-Time Energy Market or (b) zero.

5.6 Calculation of Additional Payments and Charges

5.6.1 Bid Revenue Sufficiency Guarantee: Resources scheduled for Regulation in the Real-Time Market are eligible for the Bid Revenue Sufficiency Guarantee, pursuant to Section G.2.3.

5.6.2 Failure to Provide Regulation in Real-Time: The Independent Transmission Provider shall, if a Resource providing Regulation Service trips off line, immediately attempt to re-establish a supply for the remainder of that Resource's commitment. Any additional cost incurred by the Independent Transmission Provider as a result of covering the defaulting Resource's remaining commitment shall be reimbursed to the Independent Transmission Provider by the defaulting Supplier. If the Availability payment for the replacement Regulation Service decreases, the Independent Transmission Provider shall not pay the defaulting Supplier the difference in cost.

5.6.3 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Real-Time Markets for Regulation.]

5.7 Market Rules for Shortages or Emergencies

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities and calculation of prices, in the event of a shortfall in the required system requirements for Regulation in the Real-Time Market. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

5.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases and sales of Regulation in the Real-Time Market for Regulation pursuant to Sections 5.8.1and 5.8.2.

5.8.1 Payments by Purchasers

(i) The Independent Transmission Provider shall calculate the total obligation for Regulation for each Load-Serving Entity for each hour of the Operating Day. The total hourly obligation for each Load-Serving Entity in an Operating Day shall equal the product of (a) the total Regulation requirement for the Independent Transmission Provider's Service Area for the hour of the Operating Day and (b) the ratio of (1) the Load-Serving Entity's total actual Load in the hour to (2) the total actual Load in the Independent Transmission Provider's Service Area in the hour of the of the Operating Day. The net obligation for Regulation of a Load-Serving Entity in an hour of the Operating Day shall be equal to the greater of (a) the Load-Serving Entity's total obligation minus the amount of Regulation that it has Self-Supplied in the Day-Ahead Market or (b) zero.

(ii) For each hour of the Operating Day, each Load-Serving Entity shall be charged an amount equal to the product of (1) the aggregate net amount paid by the Independent Transmission Provider in the Day-Ahead and Real-Time Markets to procure Regulation for the hour, and (2) the ratio of (a) the Load-Serving Entity's net obligation for Regulation in the hour to (b) the sum of the net obligations for Regulation of all Load-Serving Entities in the Independent Transmission Provider's Service Area in the hour.

5.8.2 Payments to Suppliers

(i) The Independent Transmission Provider shall pay Suppliers the Real-Time Regulation Market Clearing Price times the quantity (MW) of Regulation capability.

(ii) The Independent Transmission Provider shall pay Suppliers any Additional Payments necessary to provide Real-Time Regulation in accord with efficient market operations.

5.9 Monitoring Suppliers and Generators

(i) The Independent Transmission Provider may establish:

(1) Resource performance measurement criteria;

(2) Procedures to disqualify Suppliers using Resources that consistently fail to meet such criteria; and

(3) Procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.

(ii) The Independent Transmission Provider shall establish and implement a Performance Tracking System to monitor the performance of Resources that provide Regulation Service.

(iii) Payments by the Independent Transmission Provider to each Supplier of Regulation Service may be based on the Resource's performance with respect to the performance indices. Suppliers that fail to perform at a level consistent with these indices may forfeit all or a substantial portion of their Availability payments, which would otherwise be payable for the subject hour. Suppliers that consistently fail to perform adequately may be disqualified by the Independent Transmission Provider, pursuant to Independent Transmission Provider Procedures. [The Independent Transmission Provider would include such procedures in this section.]

6. Real-Time Market for Operating Reserve—Spinning Reserve

6.1 General: The Transmission Provider may require additional Spinning Reserves capability in response to system conditions in the Operating Day. The Real-Time Market for Spinning Reserve establishes clearing prices and settlement rules for eligible Suppliers of Spinning Reserve that have offered Spinning Reserve capacity to the market. The Transmission Provider shall procure Regulation in this market on behalf of Purchasers who choose not to Self-supply or purchase through Bilateral Contracts. Both Generation and Load may Bid to provide Spinning Reserve in the Real-Time Market if they meet criteria for eligibility.

6.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (viii) for the Real-Time Market for Spinning Reserve. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Spinning Reserve criteria and requirements in accord with local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS rules for eligibility to supply Spinning Reserve in the Real-Time Market.

(iii) Establish and post on its OASIS minimum technical requirements and performance standards for a Generator and/or Load to provide Spinning Reserve.

(iv) Establish and post on its OASIS the Bid data requirements and rules and provide the market functions required for determination of hourly Real-Time Spinning Reserve Market Clearing Prices and selection of Real-Time Spinning Reserve Market Suppliers. It shall make this selection with the objective of minimizing the cost of meeting Load and providing all necessary Ancillary Services in that hour. Establish how the pricing rules and selection procedures will be modified in the event of a shortage of Spinning Reserve capacity during the Operating Day.

(v) Establish and post on its OASIS the rules for determination of any Additional Payments necessary to support efficient operations of the Real-Time Spinning Reserve Market and/or the efficient operation of other Real-Time Markets.

(vi) Provide the Settlement functions associated with purchase and sale of Spinning Reserve in the Real-Time Market.

(vii) Post the Real-Time Spinning Reserve Market Clearing Prices.

6.3 Purchaser Rules and Obligations

6.3.1 Market Participants with a Spinning Reserve Requirement may fulfill their requirement by

(i)(1) self-supplying an eligible Generator or Demand-Side Resource; (2) a bilateral contract with an eligible Supplier; or (3) purchasing from the Spinning Reserve Market.

(ii) Self-suppliers and purchasers of Spinning Reserve through Bilateral Contract must provide data on location and physical capabilities of the Generator or Supplier providing Spinning Reserve (see Section 4.2)

6.4 Supplier Rules and Obligations: Suppliers whose Generators or demand side Resources have not been scheduled to provide Spinning Reserve and which still have Capacity that is synchronized with the grid and has not been committed for use in any other way may submit Bids to provide Spinning Reserve to the Independent Transmission Provider.

6.4.1 Eligibility to Supply

(i) Suppliers of Spinning Reserve may only use Generators and/or Load that are electrically within the Independent Transmission Provider's Service Area.

(ii) Suppliers of Spinning Reserve may only use Generators and/or Load that meet Independent Transmission Provider standards for Generator performance.

(iii) Suppliers may not contract to provide, or otherwise commit any Capacity from a Generator that has been scheduled to operate or to provide Operating Reserves, in either the Day-Ahead commitment or any supplemental commitment conducted by the Independent Transmission Provider.

(iv) Suppliers of Spinning Reserve shall not use, contract to provide, or otherwise commit the capability that is designated to provide Spinning Reserve to provide Energy, Regulation or Supplemental Reserve to any party other than the Independent Transmission Provider. Suppliers may enter into alternate sales arrangements utilizing any capacity that has not been scheduled to operate or to provide Operating Reserves.

(v) Suppliers of Spinning Reserve shall provide the Bid information specified in Section 4.2.

(vi) Suppliers may not increase the Energy Bids made for the portions of those Generators that have been scheduled Day-Ahead to provide Spinning Reserve.

(vii) Suppliers selected for Spinning Reserve in the Day-Ahead Market may not re-submit that capacity at a higher price into the Real-Time Market for Spinning Reserve. They may lower the Bid Price of the capacity not selected Day-Ahead to ensure selection in the Real-Time Market.

6.4.2 Specification of Bids: Suppliers of Spinning Reserve must provide the following Bid information:

(i) Response Rate (MW/Minute) of the Generator supplying Spinning Reserve.

(ii) Hours of availability to provide Spinning Reserve.

(iii) Any additional physical data required by the Independent Transmission Provider.

6.5 Calculation of Market Clearing Price

6.5.1 Methodology for Calculation of Prices: The Independent Transmission Provider shall calculate a Market Clearing Price for the Real-Time Market for Spinning Reserve, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Spinning Reserve Price for each Supplier based on its Real-Time Unit-Specific Opportunity Cost (as defined below). The Real-Time Spinning Reserve Market Clearing Price shall be the higher of (i) the highest Supplier Spinning Reserve Price for each Dispatch Interval needed to meet the Independent Transmission Provider's Spinning Reserve Requirement, or (ii) the highest Market Clearing Price in the Dispatch Interval for Supplemental Reserves.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Spinning Reserve shall be equal to the product of:

(i) the deviation of the set point (MWh) of the Generator that is required to provide Spinning Reserve from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the greater of (a) the $/MWh difference between the Real-Time Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Spinning Reserve set point for the Resource) in the Real-Time Energy Market or (b) zero.

6.5.2 Calculation of Zonal or Locational Prices: Separate Real-Time Spinning Reserve Market Clearing Prices will be calculated for Spinning Reserve located in each distinct Reserve Location for which there is a separate Spinning Reserve requirement. When there are no binding transmission constraints between Reserve Locations, the Real-Time Spinning Reserve Market Clearing Price shall be the same in each of the locations.

6.5.3 Transmission for Operating Reserves. A Supplier located outside of a particular Reserve Location may provide Spinning Reserves if the necessary transmission arrangements to deliver Energy from the Supplier's capacity to the Reserve Location are made. The cost of any transmission service would have to be included in evaluating the total cost of Operating Reserves.

Suppliers scheduled for Spinning Reserve shall not receive Opportunity Cost payments for capacity that was not available to be scheduled to generate Energy.

6.6 Calculation of Additional Payments and Charges

6.6.1 Bid Revenue Sufficiency Guarantee: Resources scheduled for Spinning Reserve in the Real-Time Market are eligible for the Bid Revenue Sufficiency Guarantee, pursuant to Section G.2.3.

6.6.2 Failure to Perform in Real-Time: When reserve is activated, the Independent Transmission Provider shall measure actual performance against expected performance and may charge financial penalties to Suppliers of Spinning Reserve which fail to perform in accordance with their accepted Bids. [The Independent Transmission Provider may file penalties.]

6.6.3 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Real-Time Markets for Spinning Reserves.]

6.7 Market Rules for Shortages or Emergencies

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities, calculation of market clearing prices, and determination of out of market payments in the event of a shortfall in the required system requirements for Spinning Reserves due to a shortage of available capacity or an Emergency.]

(ii) In the event of a shortfall of total capacity available for Operating Reserves in the Real-Time Market, the Independent Transmission Provider shall first reduce the amount of Supplemental Reserve that is procured, followed by the amount of Supplemental Reserve, followed by the amount of Spinning Reserve.

6.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases of Spinning Reserves and sales of Spinning Reserve in the Real-Time Market for Spinning Reserve pursuant to Sections 6.8.1 and 6.8.2.

6.8.1 Payments by Purchasers

(i) The Independent Transmission Provider shall calculate the total obligation for Spinning Reserve for each Load-Serving Entity for each hour of the Operating Day. The hourly total obligation of each Load-Serving Entity in an Operating Day shall equal the product of (a) the total Spinning Reserve Requirement for the Independent Transmission Provider's Service Area for the hour of the Operating Day and (b) the ratio of (1) the Load-Serving Entity's total actual Load in the hour to (2) the total actual Load in the Independent Transmission Provider's Service Area in the hour of the Operating Day. The net obligation for Spinning Reserve of a Load-Serving Entity in an hour of the Operating Day shall be equal to the greater of the Load-Serving Entity's total obligation minus the amount of Spinning Reserve that is Self-Supplied in the Day-Ahead Market or (b) zero.

(ii) For each hour of the Operating Day, each Load-Serving Entity shall be charged an amount equal to the product of (1) the aggregate net amount paid by the Independent Transmission Provider in the Day-Ahead and Real-Time Markets to procure Spinning Reserve for the hour and (2) the ratio of the Load-Serving Entity's net obligation for Spinning Reserve in the hour to the sum of the net obligations for Spinning Reserve of all Load-Serving Entities in the Independent Transmission Provider's Service Area in the hour.

6.8.2 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier selected to provide more Spinning Reserve in an hour than it was scheduled Day-Ahead the Real-Time Spinning Reserve Market Clearing Price at its location, multiplied by the amount (MW) of Spinning Reserve that Supplier provided that was in excess of the amount scheduled to be provided Day-Ahead, if any.

6.8.3 Payments by Suppliers

(i) The Supplier shall pay the Independent Transmission Provider for any Spinning Reserve that it was scheduled Day-Ahead to provide in an hour but did not provide. The payment will be the Real-Time Spinning Reserve Market Clearing Price at its location, multiplied by the amount (MW) of scheduled Spinning Reserve that Supplier did not provide.

(ii) The Supplier shall pay the Independent Transmission Provider any Additional Payments associated with failure to perform according to its Real-Time schedule, pursuant to Section 6.6.

6.9 Failure to Provide Operating Reserves: If a Supplier reduces its available capacity subsequent to being scheduled to provide Regulation Service or Operating Reserves (either Day-Ahead or in a commitment of Replacement Reserves), and if the Independent Transmission Provider must, as a result, reduce the amount of Operating Reserves that Supplier is scheduled to provide in accordance with this Tariff, the Independent Transmission Provider will first reduce the lowest quality Supplemental Reserve that Generator is scheduled to provide.

If it is still necessary to reduce the amount of Operating Reserves that Supplier is scheduled to provide, the Independent Transmission Provider will reduce the amount, in order of quality, of the higher quality Supplemental Reserves that Generator is scheduled to provide.

Finally, if it is still necessary to reduce the amount of Operating Reserves that Supplier is scheduled to provide, the Independent Transmission Provider will reduce the amount of Spinning Reserve that Generator is scheduled to provide.

If a Supplier scheduled Day-Ahead to provide Operating Reserves trips off-line and consequently is unable to provide Spinning Reserve, or if the amount of Operating Reserves a Supplier is scheduled to provide is decreased due to a reduction in that Supplier's capacity, it shall be charged the Real-Time Operating Reserve price at its location in each hour for the relevant category of Operating Reserves applied to the reduction in the amount of Operating Reserves it was scheduled Day-Ahead to provide at that location.

If the Independent Transmission Provider calls for a Supplier of any category of Operating Reserves (other than a Supplier that has previously tripped off-line) to generate Energy with part or all of the capacity that the Independent Transmission Provider has scheduled to provide any category of Operating Reserves, and that Supplier fails to provide the amount of Energy requested by the Independent Transmission Provider within the time applicable for the scheduled Operating Reserves, the Independent Transmission Provider shall:

(i) not pay the non-performing Supplier for any shortfall in the amount of Energy provided;

(ii) charge the Supplier for any shortfall in the amount of Energy provided, at the Real-Time LMP for Energy at that Supplier's location;

(iii) charge the Supplier a regulation penalty; and

(iv) reduce any Availability payments for the scheduled Operating Reserves, and any Opportunity Cost payments, if applicable, that the Supplier would otherwise have received for the 24-hour billing period in which that Supplier failed to perform as scheduled. The Availability payments and the Opportunity Cost payments, if applicable, that the Supplier would have received will be calculated by multiplying the average ratio of the amount of Energy supplied to the amount of Energy scheduled, during any activation of that Supplier during that 24-hour billing period by the applicable Availability payments and Opportunity Cost payments, if applicable, that the Supplier would otherwise have received.

If a Generator providing Operating Reserves has repeatedly failed to provide Energy when called upon by the Independent Transmission Provider, the Independent Transmission Provider may preclude that Generator from providing Operating Reserves in the future. If a specific Generator has been precluded from supplying Operating Reserves, the Independent Transmission Provider shall require that Generator to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from that Generator.

7. Real-Time Markets for Operating Reserves—Supplemental Reserves

7.1 General: The Transmission Provider may require additional Supplemental Reserves capability in response to system conditions in the Operating Day. The Real-Time Markets for Supplemental Reserves establish clearing prices and settlement rules for eligible Suppliers of Supplemental Reserve that have offered Supplemental Reserve capacity to the market. The Transmission Provider shall procure Supplemental Reserves for Purchasers that have chosen not to Self-supply or purchase through Bilateral Contracts. Both Generation and Load may Bid to provide Supplemental Reserves in the Real-Time Market if they meet criteria for eligibility.

7.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (vii) for the Real-Time Markets for Supplemental Reserves. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Supplemental Reserves criteria and requirements in accord with local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS rules for eligibility to supply Supplemental Reserves in the Real-Time Market.

(iii) Establish and post on its OASIS minimum technical requirements and performance standards for a Generator to provide Supplemental Reserves.

(iv) Establish and post on its OASIS the Bid data requirements and rules and provide the market functions required for determination of hourly Real-Time Supplemental Reserves Market Clearing Prices and selection of Real-Time Supplemental Reserves Market Suppliers. Establish how the pricing rules and selection procedures will be modified in the event of a shortage of Supplemental Reserves capacity during the Operating Day.

(v) Establish and post on its OASIS the rules for determination of any Additional Payments necessary to support efficient operations of the Real-Time Supplemental Reserves and/or the efficient operation of other Real-Time Markets.

(vi) Provide the Settlement functions associated with purchase and sale of Supplemental Reserves in the Real-Time Market.

(vii) Post the Real-Time Supplemental Reserves Market Clearing Prices.

7.3 Purchaser Rules and Obligations

(i) Market Participants with Supplemental Reserves requirements may fulfill their requirement by (1) self-supplying an eligible Generator or Demand-Side Resource, (2) a bilateral contract with an eligible Supplier, or (3) purchasing from the Supplemental Reserves Market.

(2) Self-suppliers and purchasers of Supplemental Reserves through Bilateral Contracts must provide data on location and physical capabilities of the Generator or Supplier providing Supplemental Reserve (see Section 4.2).

7.4 Supplier Rules and Obligations:

(i) During the day, Suppliers that have not been scheduled to provide Supplemental Reserves and which still have capacity that has not been committed for use in any other way may submit Bids to provide Supplemental Reserves to the Independent Transmission Provider.

(ii) The Real-Time Bids may differ from Bids that were made by those Suppliers in the Day-Ahead commitment subject to possible Bid restrictions imposed to mitigate market power.

(iii) Suppliers Bidding to supply Supplemental Reserves that have not already been scheduled to provide Supplemental Reserves may change their Real-Time Bids from one hour to the next subject to possible Bid restrictions imposed to mitigate market power.

(iv) The Independent Transmission Provider shall notify each Supplier of Supplemental Reserves that has been scheduled in the Real-Time dispatch of the amount of Supplemental Reserves it must provide. Any Supplier whose Bid to provide Supplemental Reserves is accepted by the Independent Transmission Provider in the Real-Time dispatch must make its Generators or demand side Resources available for dispatch by the Independent Transmission Provider. Suppliers of Supplemental Reserves shall respond to direction by the Independent Transmission Provider to activate.

7.4.1 Eligibility to Supply

(i) Subject to Independent Transmission Provider requirements, Suppliers of Supplemental Reserves may use Generators and/or Load that are electrically within or outside the Independent Transmission Provider's Service Area.

(ii) Suppliers of Supplemental Reserve may only use Generators and/or Load that meet Independent Transmission Provider standards for Generator performance.

(iii) Suppliers of Supplemental Reserves shall not use, contract to provide, or otherwise commit the capability that is designated to provide Supplemental Reserves to provide Energy, Regulation or Spinning Reserve to any party other than the Independent Transmission Provider.

(iv) Suppliers of Supplemental Reserves shall provide the Bid information specified in Section 4.2.

(v) Suppliers may not use, contract to provide or otherwise commit any capacity on any Resource that has been scheduled to provide Supplemental Reserves in the Day-Ahead commitment or in the Real-Time dispatch.

7.4.2 Specification of Bids: Suppliers of Supplemental Reserves must provide the following Bid information:

(i) Response Rate (MW/Minute) of the Generator supplying Supplemental Reserve.

(ii) Hours of availability to provide Supplemental Reserve.

(iii) Any additional physical data required by the Independent Transmission Provider.

7.5 Calculation of Market Clearing Price for Supplemental Reserve

7.5.1 Methodology for Calculation of Prices: The Independent Transmission Provider shall calculate a Market Clearing Price for each Real-Time Market for Supplemental Reserves, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Supplemental Reserve Price for each Supplier based on Unit-Specific Opportunity Cost (as defined below). The Real-Time Supplemental Reserve Market Clearing Price shall be the higher of (i) the highest Supplier Supplemental Reserve Price needed to meet the Independent Transmission Provider's Supplemental Reserve Requirement for each Dispatch Interval, or (ii) the Market Clearing Price in any Dispatch Interval for any lower quality Supplemental Reserve.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Supplemental Reserve in each Dispatch Interval shall be equal to the product of:

(i) the deviation of the set point (MWh) of the Generator that is required in order to provide Supplemental Reserve from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the absolute value of the difference between the Real-Time Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Supplemental Reserve set point for the Resource) in the Real-Time Energy Market.

7.5.2 Calculation of Zonal or Locational Prices. Separate Real-Time Supplemental Reserve Market Clearing Prices will be calculated for Supplemental Reserve located in each distinct Reserve Location for which there is a separate Supplemental Reserve requirement. When there are no binding transmission constraints between Reserve Locations, the Real-Time Ancillary Price for Supplemental Reserve shall be the same in each of the locations.

7.5.3 Transmission for Operating Reserves. A Supplier located outside of a particular Reserve Location may provide Supplemental Reserve if the necessary transmission arrangements to deliver Energy from the Supplier's capacity to the Reserve Location are made. The cost of any transmission service would have to be included in evaluating the total cost of Operating Reserves.

7.6 Calculation of Additional Payments and Charges

7.6.1 Bid Revenue Sufficiency Guarantee: Resources scheduled for Supplemental Reserves in the Real-Time Market are eligible for the Bid Revenue Sufficiency Guarantee, pursuant to Section G.2.3.

7.6.2 Failure to Perform in Real-Time: When reserve is activated, the Independent Transmission Provider shall measure actual performance against expected performance and shall charge financial penalties as detailed in Section 6.9, to Suppliers of Reserves which fail to perform in accordance with their accepted Bids. [The Independent Transmission Provider may file penalties.]

7.6.3 Exceptions: Notwithstanding anything to the contrary in this Rate Schedule, no payments shall be made to any Supplier providing Operating Reserves for reserves provided by that Supplier in excess of the amount of Operating Reserves scheduled by the Independent Transmission Provider either Day-Ahead or in any subsequent schedule.

The market clearing price paid to Suppliers of any category of Operating Reserve shall not be determined by any Bid to supply Operating Reserve that has not been accepted by the Independent Transmission Provider.

7.6.5 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Real-Time Markets for Supplemental Reserves.]

7.7 Market Rules for Shortages or Emergencies:

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities, calculation of market clearing prices, and determination of out of market payments in the event of a shortfall in the required system requirements for Supplemental Reserves due to a shortage of available capacity or an Emergency.]

(ii) In the event of a shortfall of total capacity available for Supplemental Reserves in the Real-Time Market, the Independent Transmission Provider shall first reduce the amount of any lower quality Supplemental Reserve that is procured, in order of quality, followed by the amount of higher quality Supplemental Reserves.

7.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases of Supplemental Reserves and sales of Supplemental Reserves in the Real-Time Market pursuant to Sections 7.8.1 and 7.8.2.

7.8.1 Payments by Purchasers

(i) The Independent Transmission Provider shall calculate the total obligation for Supplemental Reserve for each Load-Serving Entity for each hour of the Operating Day. The hourly total obligation of each Load-Serving Entity in an Operating Day shall equal the product of (a) the total Supplemental Reserve Requirement for the Independent Transmission Provider's Service Area for the hour of the Operating Day and (b) the ratio of (1) the Load-Serving Entity's total actual Load in the hour to (2) the total actual Load in the Independent Transmission Provider's Service Area in the hour of the Operating Day. The net obligation for Supplemental Reserve of a Load-Serving Entity in an hour of the Operating Day shall be equal to the greater of the Load-Serving Entity's total obligation minus the amount of Supplemental Reserve that is Self-Supplied in the Real-Time Market or (b) zero.

(ii) For each hour of the Operating Day, each Load-Serving Entity shall be charged an amount equal to the product of (1) the aggregate net amount paid by the Independent Transmission Provider in the Real-Time Markets to procure Supplemental Reserve for the hour and (2) the ratio of the Load-Serving Entity's net obligation for Spinning Reserve in the hour to the sum of the net obligations for Supplemental Reserve of all Load-Serving Entities in the Independent Transmission Provider's Service Area in the hour.

7.8.2 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier selected to provide more Supplemental Reserve in an hour than it was scheduled Day-Ahead the Real-Time Supplemental Reserve Market Clearing Price at its location, multiplied by the amount (MW) of Supplemental Reserve that Supplier provided that was in excess of the amount scheduled to be provided Day-Ahead, if any.

7.8.3 Payments by Suppliers

(i) The Supplier shall pay the Independent Transmission Provider for any Supplemental Reserves that it was scheduled Day-Ahead to provide in an hour but did not provide. The payment will be the Real-Time Supplemental Reserve Market Clearing Price at its location, multiplied by the amount (MW) of Day-Ahead scheduled Supplemental Reserve that the Supplier did not provide.

(ii) The Supplier shall pay the Independent Transmission Provider any Additional Payments associated with failure to perform according to its Real-Time schedule, pursuant to Section 7.6.3.

8. Other Real-Time Payments and Charges

8.1 Bid Revenue Sufficiency Guarantee Payments for Replacement Reserves

8.1.1 Payments to Suppliers. The Independent Transmission Provider shall determine, on a daily basis, if any Resource that it has committed to provide Replacement Reserves for the operating day pursuant to Section F.1.8 has not recovered its Start-up, No-load, and Energy Bid Prices through revenues in the Real-Time Energy and Ancillary Services Markets. If the Start-up, No-load, and Energy Bids over the twenty-four (24) hour Operating Day of any such Resource exceed its combined Revenue from the Real-Time Markets for Energy and Ancillary Services, then that Resource's revenue shall be augmented by an additional payment, called the Real-Time Bid Revenue Sufficiency Guarantee payment, in the amount of the revenue shortfall.

8.1.2 Charges to Customers. A purchase of Real-Time Energy is deemed to be made by any Customer whose actual Energy injections in any hour of the Operating Day is less than its injections scheduled for that hour in the Day-Ahead Market, and by any Customer whose actual Energy withdrawals in any hour in the Operating Day exceed its withdrawals scheduled for that hour in the Day-Ahead Market. All uninstructed purchases of Real-Time Energy, *i.e.,* Real-Time Energy purchased by a Customer without being instructed to do so by the Independent Transmission Provider, shall be subject to a Replacement Reserves charge. The Independent Transmission Provider shall calculate Replacement Reserves charges for the Operating Day as follows. The Independent Transmission Provider shall calculate the sum of all uninstructed purchases of Real-Time Energy over the Operating Day and shall compare that sum to the aggregate MWhs of Replacement Reserves that it committed over the Operating Day pursuant to Section F.1.8.

(i) If the sum of all uninstructed purchases of Real-Time Energy greater than or equal to the aggregate MWhs of Replacement Reserves committed over the Operating Day, then the Replacement Reserve charge for each Customer i shall be calculated as:

Replacement Reserve charge for Customer i = $(P/U) \times u_i$;

where:

P is the sum of the aggregate payments made pursuant to Section G.8.1.1 for the Operating Day;

U is the sum of all uninstructed purchases of Real-Time Energy by all Customers (in MWhs) over the Operating Day; and

u_i is the aggregate uninstructed purchases of Real-Time Energy by Customer i over the Operating Day.

(ii) If the sum of all uninstructed purchases of Real-Time Energy is less than the aggregate MWhs of Replacement Reserves committed over the Operating Day, then the Replacement Reserve charge for each Customer i shall be calculated as:

Replacement Reserve charge for Customer i = $(P/R) \times d$;

where:

P is the sum of the aggregate payments made pursuant to Section G.8.1.1 for the Operating Day;

R is the aggregate MWhs of Replacement Reserves that the Independent Transmission Provider has committed over the Operating Day pursuant to Section F.1.8.

u_i is the aggregate uninstructed purchases of Real-Time Energy by Customer i over the Operating Day.

8.1.3 Unrecovered Bid Revenue Sufficiency Guarantee Payments. Any amounts of Bid Revenue Sufficiency Guarantee payments for an Operating Day made pursuant to Section G.8.1.1 that are not recovered through Replacement Reserve charges for the Operating Day pursuant to Section G.8.1.2 shall be recovered in a separate charge to all Load-Serving Entities in the Independent Transmission Provider's Service Area. The charge for each Load-Serving Entity for the Operating Day shall equal to the product of (a) the total amounts of Bid Revenue Sufficiency Guarantee payments for an Operating Day made pursuant to Section G..8.1.1 that are not recovered through Replacement Reserve charges for the Operating Day pursuant to G.8.1.2 and (b) the ratio of (1) the Load-Serving Entity's total actual Load over the Operating Day to (2) the total actual Load within the Independent Transmission Provider's Service Area over the Operating Day.

8.2 Other Real-Time Bid Revenue Sufficiency Guarantee Payments

8.2.1 Payments to Suppliers. The Independent Transmission Provider shall pay each Resource scheduled, committed, or dispatched by the Independent Transmission Provider after the close of the Day-Ahead Market (other than a Resource committed to supply Replacement Reserves) the real-time Bid Revenue Sufficiency Guarantee payment for the Operating Day, calculated pursuant to Section G.2.3(ii).

8.2.2 Charges to Customers. A purchase of Real-Time Energy is deemed to be made by any Customer whose actual Energy injections in any hour of the Operating Day is less than its injections scheduled for that hour in the Day-Ahead Market, and by any Customer whose actual Energy withdrawals in any hour in the Operating Day exceed its withdrawals scheduled for that hour in the Day-Ahead Market. Each Customer purchasing Real-Time Energy shall pay a Real-Time Bid Revenue Sufficiency Guarantee payment. The Bid Revenue Sufficiency Guarantee payment for any Customer i for the Operating Day shall be calculated based on the following formula:

Bid Revenue Sufficiency Guarantee for Customer i = $G \times (C^i / D)$

where:

G is the sum of all Bid Revenue Sufficiency Guarantee payments made for the Operating Day pursuant to Section G.8.2.1;

C_i is the total purchases of Real-Time Energy by Customer i during the Operating Day; and

D is the sum of the total purchases of Real-Time Energy by all Customers over the Operating Day.

Part IV. Market Monitoring

Each Independent Transmission Provider must file a market monitoring plan in accordance with the Commission's regulations as part of this Tariff.

H. Market Power Mitigation and Market Monitoring

1. Market Power Mitigation

1.1 Participating Generator Agreements: The participating generator agreement between the Independent Transmission Provider and a generator will include a provision to require that all available capacity of the generator must be scheduled or offered to the Day-Ahead and Real-Time markets at bids that do not exceed specified Bid caps under non-competitive conditions to be specified in the agreement.

1.2 Determination of Bid Caps

1.2.1 The Safety-Net Bid Cap: The MMU will establish a safety-net Bid cap that will apply to all markets at all times.

1.2.2 Generator-specific Bid Caps: The MMU will establish for each Generator identified in Section H.1.4.1 below Bid caps that may apply to each Bid-in parameter when mitigation is warranted. These shall include: Bid caps for Energy, regulation service, operating reserves, start-up costs, no-Load costs, incremental and decremental Energy costs, and any other parameter allowed to vary in Day-Ahead and Real-Time markets.

1.3 Determination of Available Capacity: Available capacity is all capacity not scheduled or on an outage.

1.3.1 Adjustments to Available Capacity to Reflect Risk of Forced Outages in Real-Time Market: Independent Transmission Provider may file provisions.

1.3.2 Available Capacity Reduced by Forced Outages Subject to Audit: Units declaring a forced outage would be subject to audit by the MMU. If the outage was not proved to be justified, then the Generator shall be subject to a penalty. [The Independent Transmission Provider shall specify the type of penalty.]

1.4 Determination of Non-competitive Conditions

1.4.1 Local Non-competitive Conditions: The MMU shall identify specific Generators that are frequently needed to support the operation of the grid and sellers that own facilities in identified Load pockets with fewer than ____ independent suppliers. Participating Generator Agreements for these entities will require that they be subject to Local Market Power Mitigation.

1.4.2 Other Non-competitive Conditions: The MMU shall identify other non-competitive conditions as necessary.

1.5 Triggering Mitigation

1.5.1 Market Power Mitigation Independent of Market Conditions: The Independent Transmission Provider may not accept any Bid into the Day-Ahead or Real-Time markets that exceeds the higher of: (a) the safety-net Bid cap specified in Section H.1.2.1; or (b) the bid cap specified in a Participating Generator Agreement.

1.5.2 Market Power Mitigation Triggered by Section H.1.4.1: When mitigation is triggered by Section H.1.4.1, the units will be required to offer all available capacity to the Day-Ahead and Real-Time markets at bids that do not exceed applicable bid caps determined in H.1.2.2.

1.5.3 Market Power Mitigation Triggered by Section H.1.4.2: To be specified.

2. Market Monitoring Plan

The transmission and power markets administered by the Independent Transmission Provider will be monitored on an on-going basis by the Market Monitoring Unit (MMU). The MMU reports directly to the Commission and the governing board of the transmission provider.

2.1 Data Requirements and Data Collection: The MMU shall collect and evaluate data provided by the Independent Transmission Provider and Market Participants in order to identify inefficiencies in the markets or the market design, and individual Market Participant behavior that may be a prohibited exercise of market power or a violation of this Tariff or other market rules.

2.1.1 Obligations of Market Participants: As a condition of participating in the markets operated by the Independent Transmission Provider, all Market Participants shall be required to comply with information requests from the MMU. Any disputes concerning whether the information is necessary or how the information is to be provided or how any confidential information could be used should first be attempted to be resolved either through dispute resolution or the Commission's Office of Market Oversight and Investigations (Hotline). If the parties are then unable to resolve the dispute, a complaint under Section 206 of the Federal Power Act may be filed.

2.1.2 Generator-Specific data: The MMU shall have the responsibility to collect all Generator-specific data needed to evaluate whether a seller is exercising market power and to establish Bid restrictions that may be imposed when markets are not sufficiently competitive. The data shall include, at a minimum: start-up, no Load, and shut-down costs, environmental restrictions, fuel costs, maintenance costs, heat rates, ramp rates, high and low operating levels, and minimum run times.

2.1.3 Data Acquired in the Course of Conducting Market Operations: The MMU shall have immediate access to all Bid data submitted to the Independent Transmission Provider.

2.1.4 Other Publically Available Data: The Market Monitor shall collect all data needed to assess the overall competitiveness of its markets. The data would include, but not be limited to, information on market shares of Generation Capacity by type and location, information on planned and unplanned Generator and transmission outages, and plans for transmission expansions and upgrades, and Generator interconnection requests.

2.1.5 Confidentiality: All information obtained by the MMU, that is specific to a Market Participant, shall be treated confidentially.

2.2 Framework for Analyzing Market Structure and Generator Conduct

2.2.1 Obligations of the Market Monitor: The MMU shall conduct a structural analysis of the markets in the region to include in a state of the market report to the Commission, the committee of state representatives, and the transmission provider's Board of Directors. In addition, the MMU must evaluate the conduct of Market Participants. Any flaws in the market rules that are identified by the Market Monitor, and any Market Participant conduct that indicates exercises of market power, shall be remedied prospectively, unless the conduct violates existing rules, in which case the consequences shall be predetermined and specified in this Tariff.

2.2.1 Structural Analysis: The MMU shall develop an analysis of the overall competitiveness of the markets operated by the Transmission Provider. The analysis will be performed at least annually and will report on the following at a minimum: market concentration by Generator type and region, transmission constraints and Load pockets that may give rise to market power concerns, conditions for entry or new supply, the development of demand response, and development of a competitive benchmark.

2.2.2 Conduct Analysis: The MMU will monitor the conduct of individual Market Participants. The Market Monitor shall review planned transmission and generation outages to ensure that scheduling outages are not used to enhance or create opportunities to exercise Generator market power. Analysis of Market Participant conduct may include a review of Bidding behavior to identify any auction design flaws that may give Market Participants an unanticipated incentive and ability to manipulate market-clearing prices or up-lift payments. Finally, the Market Monitor shall evaluate the effectiveness of the Participating Generator Agreements in mitigating market power where market structure is not sufficiently competitive.

2.3 Annual Reports: No later than May 31 of each year, the Market Monitor shall file a State of the Markets Report with the Commission which includes the results of the Market Monitor's structural and conduct analyses. This report shall address such items as market concentration, demand response programs, Load pockets, and transmission constraints and an assessment of the performance of the markets administered by the Transmission Provider. In addition, this report shall identify any actions taken by the Market Monitor.

2.4 Periodic Reports: The Market Monitor shall submit a report to the Commission if it detects behavior that cannot be cured within the Market Monitor's authority or if it detects behavior that would require a change in market rules. These reports should be made as soon as practicable after the behavior is detected.

3. Rules for Market Participant Conduct: Market Participants must comply with the following rules:

3.1 Physical Withholding: Entities may not physically withhold the output of an Electric Facility (Generating unit or Transmission Facility) by (a) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, or (b) failing to comply Section H.1.5.2.

3.2 Economic Withholding: Entities may not economically withhold by submitting high bids that are not consistent with the caps specified in Section H.1.2.

3.3 Availability Reporting: Entities must comply with all reporting requirements governing the availability and maintenance of a Generating Unit or Transmission Facility, including proper Outage scheduling requirements. Entities must immediately notify the Transmission Provider when capacity changes or resource limitations occur that affect the availability of the unit or facility or the ability to comply with dispatch instructions.

3.4 Factual Accuracy: All applications, schedules, reports, or other communications to the Transmission Provider or the Market Monitor must be submitted by a responsible company official who is knowledgeable of the facts submitted. All information submitted must be true to the best knowledge of the person submitting the information.

3.5 Information Obligation: Entities must comply with requests for information or data by the Market Monitor or the Transmission Provider that are consistent with the Tariff.

3.6 Cooperation: Entities must assist and cooperate in investigations or audits conducted by the Market Monitor.

3.7 Physical Feasibility: All Bids or schedules that designate Resources must be physically feasible within the limits of the Resource, *i.e.,* the Resource is physically capable of supplying the Energy, Ancillary Service, or demand response needed to fulfill a schedule or Bid according to the physical limitations of the Resource.

3.8 Enforcement: The Market Monitor is responsible for the enforcement of the rules in this section. Violations of these rules will be subject to the following penalties: [to be added]

I. Long-Term Resource Adequacy

This section sets forth terms and conditions requiring each Load-Serving Entity to meet its share of the region's Resource Adequacy Requirement. The Resource Adequacy Requirement will ensure that in the future each Load-Serving Entity will have secured generation, transmission, and demand response resources sufficient to meet real-time load and a reasonable operating reserve margin necessary to maintain the stable and reliable operation of the transmission system.

[Additional details will be completed and filed by each Independent Transmission Provider as part of its compliance filing.]

1. Data Submission for the annual forecast of future regional load

(i) [There may be regional variation in forecast methodology. Some regions may wish to do a bottom up forecast. The following wording will then be needed.] [Annually, on or before ________ (each Independent Transmission Provider shall insert the relevant date here), each Load Serving Entity shall submit its demand forecast for the Planning Horizon.]

2. Assignment of Resource Adequacy Requirements

(ii) Annually, on or before ________ [each Independent Transmission Provider shall insert the relevant date here], the Independent Transmission Provider shall assign a share of the region's Resource Adequacy Requirement to each Load Serving Entity within the region based on the ratio of the load.

3. Load Serving Entity's submission for Resource Adequacy Requirements

(i) Annually, on or before ________ [each Independent Transmission Provider shall insert the relevant date here], each Load Serving Entity shall submit a proposed plan to meet its assigned Resource Adequacy Requirement to the Independent Transmission Provider.

(ii) Plans for meeting the assigned Resource Adequacy Requirement may rely upon generation, transmission, and/or demand response, subject to the standards set forth in this section of the Tariff, and Independent Transmission Provider's review of operational feasibility.

(iii) The Independent Transmission Provider shall audit each plan for compliance with the standards set forth in Section I.4 and for operational feasibility. [Each Independent Transmission Provider shall establish a review and resubmission process, with reasonable time frames, to achieve compliant and operationally feasible plans within a specified end date.]

4. Resource Adequacy Requirement Standards

(ii) Each Load-Serving Entity must satisfy the Independent Transmission Provider that the resources to be relied upon for future Resource Adequacy Requirements are in compliance with the standards of this section of the Tariff and are operationally feasible, dedicated to serving the Load-Serving Entity without prior or conflicting claim, and can be delivered to the load to be served as and if needed to meet future requirements.

(ii) [Each Independent Transmission Provider shall list in its open access electricity transmission Tariff specific requirements it intends to impose on each Load-Serving Entity such that the Load Serving Entity's resources qualify to meet its share of the Resource Adequacy Requirement.]

5. Penalties

[Each Independent Transmission Provider shall list in its open access electricity transmission Tariff specific penalties it intends to impose.]

(i) Each Load-Serving Entity that has not met its allocated share of the Resource Adequacy Requirement, shall be subject to penalty rates for spot market energy purchases during the last year of the Planning Horizon to the extent of the resource shortage whenever the Independent Transmission Provider's market has available less than a minimally acceptable level of operating reserves.

(ii) Penalties will increase on a graduated basis as the Independent Transmission Provider's operating reserves level falls below minimally acceptable levels. (For example, for deficiencies up to 1 percent, the penalty would be $500/MWh, plus the prevailing market price for energy. As the operating reserve level falls, the premium of the penalty over the prevailing market price for energy would increase: over 1 percent up to 2 percent, the penalty would be $600/MWh; over 2 percent up to 3 percent, the penalty would be $700/MWh; and so forth.)

6. Curtailment

(i) A Load-Serving Entity that fails to implement curtailment (load shedding) when ordered by the Independent Transmission Provider shall be assessed a penalty of $1,000 per MWh, in addition to the LMP, for all unauthorized energy taken following an instruction to implement curtailment (load shedding).

Part V. Other

J. Generation Interconnection Procedures (to be provided in a separate rule)

Part VI. Transmission Planning and Expansion

K. Transmission Planning and Expansion

Each Independent Transmission Provider must file its transmission planning and expansion plan as part of this Tariff.

Part VI. Pro Forma Service Agreements

Form Of Service Agreement For Network Access Transmission Service

1.0 This Service Agreement, dated as of__________, is entered into, by and between__________ (the Independent Transmission Provider), and __________ (''Customer'').

2.0 The Customer has been determined by the Independent Transmission Provider to have a Completed Application for Network Access Service under the Tariff.

3.0 The Customer has provided to the Independent Transmission Provider an Application deposit, if applicable, in accordance with the provisions of Section B.2.2 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) 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 Independent Transmission Provider agrees to provide and the Customer agrees to take and pay for Network Access 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.

Independent Transmission Provider:

____
____
____

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.

Independent Transmission Provider:

By: ______________________________
Name

Title ______________________________

Date ______________________________

Customer:

By: ______________________________
Name

Title ______________________________

Date ______________________________

Specifications For Network Access Service for Customers with Designated Resources and for Long-Term Customers without Designated Resources

1.0 Term of Transaction: ______________

Start Date: ______________

Termination Date: ______________

2.0 Description of capacity and Energy to be transmitted by Independent Transmission Provider including the electric Service Area in which the transaction originates. ________

____

3.0 Receipt Points or Network Resource(s):

____

Delivering Party: ______________

4.0 Delivery Points or Network Load: ______

Receiving Party: ______________

5.0 Designation of party(ies) subject to reciprocal service obligation: ______________

____
____
____

6.0 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 plus any applicable Congestion Charges. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Network Access Charge: ______________

____

8.2 System Impact and/or Facilities Study Charge(s): ______________________________

____
____

8.3 Direct Assignment Facilities Charge: __

____

8.4 Ancillary Services Charges: _________

____
____
____
____
____
____

Form of Service Agreement for Market Services

1. This Service Agreement dated as of ______________ is entered into by and between ______________ (Independent Transmission Provider) and ______________ (Customer).

2. The Customer represents and warrants that it has met all applicable requirements set forth in the Independent Transmission Provider's Tariff and has complied with all applicable Procedures under the Tariff.

3. The Independent Transmission Provider agrees to provide and the Customer agrees to pay for Market Services in accordance with the provisions of the Independent Transmission Provider's Tariff and to satisfy all obligations under the terms and conditions of the Independent Transmission's Provider's Tariff, as may be amended from time-to-time, filed with the Federal Energy Regulatory Commission (Commission). The Independent Transmission Provider and the Customer all agree that this Service Agreement shall be subject to, and shall incorporate by reference, all of the terms and conditions of the Independent Transmission Provider's Tariff and Procedures.

4. It is understood that, in accordance with the Independent Transmission Provider's Tariff, the Independent Transmission Provider may amend the terms and conditions of this Service Agreement by notifying the Customer in writing and make the appropriate filing with the Commission.

5. The Customer represents and warrants that:

(a) The Customer is an entity duly organized, validly existing and/or otherwise qualified to do business under the laws of the State of ___________ and is in good standing under its [insert organizational document] and the laws of the State of [insert state of organization];

(b) This Service Agreement, or any Transaction entered into pursuant to the Service Agreement, as applicable, has been duly authorized;

(c) The execution, delivery and performance of this Service Agreement will not materially conflict with, constitute a material breach of, or a material default under, any of the terms, conditions, or provisions of any law or order of any agency of government, the [insert organizational document] of the Customer, any contractual limitation, organizational limitation or outstanding trust indenture, deed of trust, mortgage, loan agreement, other evidence of indebtedness, or any other agreement or instrument to which Customer is a party or by which it or any of its property is bound, or in a material breach of, or a material default under, any of the foregoing; and

(d) This Service Agreement is the legal, valid, and binding obligation of the Customer enforceable in accordance with its terms, except as it may be rendered unenforceable by reason of bankruptcy or other similar laws affecting creditors' rights, or general principles of equity.

The Customer warrants and covenants that, during the term of the Service Agreement, the Customer shall be in compliance with all federal, state, and local laws, rules, and regulations related to the Customer's performance under the agreement.

4. Service under this Service Agreement shall commence on the later of: ____________, or such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate on ___________.

5. The Independent Transmission Provider agrees to provide and the Customer agrees to take and pay for, or to supply to the Independent Transmission Provider, Energy, capacity, and Ancillary Services in accordance with the provisions of the Independent Transmission Provider's Tariff and this Service Agreement.

6. 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:

Independent Transmission Provider:

____
____
____

Customer:

____
____
____

7. Cancellation Rights:

If the Commission or any regulatory agency having authority over this Service Agreement determines that any part of this Service Agreement must be changed, the Independent Transmission Provider shall offer to the Customer an amended Service Agreement reflecting such changes. In the event that the Customer does not execute such an amendment within thirty (30) days, or longer if the Parties mutually agree to an extension, after the Commission's action, this Service Agreement and the amended Service Agreement shall be void.

8. Early Termination by the Customer:

The Customer may terminate service under this Service Agreement no earlier than ninety (90) days after providing the Independent Transmission Provider with written notice of the Customer's intention to terminate; except that a Load-Serving Entity must continue to take service under the Independent Transmission Provider's Tariff as long as it continues to serve Load within the Independent Transmission Provider's Service Area. In the event that tax-exempt financing of a Customer is jeopardized by its participation under this Service Agreement, the Customer is jeopardized by its participation under this Service Agreement, the Customer may terminate this Service Agreement upon thirty (30) days written notice to the Independent Transmission Provider. The Customer's provision of notice to terminate service under this Service Agreement shall not relieve the Customer of its obligation to pay any rates, charges, or fees due under this Service Agreement, and which are owed as of the date of termination.

9. The Customer hereby appoints the Independent Transmission Provider as its agent for the limited purpose of effectively transacting on the Customer's behalf in accordance with the Customer's written instructions, listed herein and the terms of the Independent Transmission Provider's Tariff and Procedures. The Customer agrees to pay all amounts due and chargeable to the Customer in accordance with the terms of the Independent Transmission Provider's Tariff and Procedures.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Independent Transmission Provider: ______
By: ______
Dated: ______
Title: ______
Customer: ______
By: ______
Dated: ______
Title: ______

Form of Participating Generator Agreement

[To be provided by Independent Transmission Provider.]

Part VII. Attachments

Attachment A—Methodology To Assess Available Transfer Capability

To be filed by the Independent Transmission Provider based on the following guidelines:

Available Transfer Capability must be calculated on a regional basis by an independent entity. In an RTO or ISO, the Independent Transmission Provider may calculate Available Transfer Capability. Vertically integrated utilities not a part of an RTO or ISO must contract with an independent entity to calculate Available Transfer Capability on its system. The calculation of Available Transfer Capability must take into account the effect of other transmission systems in the interconnection (*e.g.*, loop flow and parallel path flows).

Attachment B—Methodology for Completing a System Impact Study

To be filed by the Independent Transmission Provider.

Attachment C—Network Operating Agreement

To be filed by the Independent Transmission Provider.

Attachment D—Index Of Network Access Service Customers

Customer	Date of Service Agreement

Attachment E—Index Of Market Services Customers

Customer	Date of Service Agreement

Attachment F—Rates

To be filed by the Independent Transmission Provider.

Attachment G—List of Existing Transmission Contracts

Customer	Commission Designation	Date of Contract	Termination Date

Appendix C—Examples of Flaws in the Current Regulatory Environment

We set forth below specific examples of undue discrimination and impediments to competition that continue to exist in the electric industry. Some of the examples that we provide do not use specific names because they are for the most part based on complaints made through the Commission's Enforcement Hotline, which are handled on a confidential basis. Other examples, which illustrate the potential for discrimination, establish that transmission providers have both the incentive and ability to exercise transmission market power against competitors in the market to supply energy.

Available Transfer Capability and Affiliates

The following is an example derived from informal, non-public inquiries to the Commission [1] regarding a transmission provider favoring itself or its affiliate using Available Transfer Capability postings:

In February, a competing generator recognizes an opportunity to sell power into a vertically integrated transmission provider's system during the summer months (June, July, and August) and, therefore, requests monthly firm service for the desired points for that time period. The transmission provider, which would prefer that its merchant function capture the sales anticipated by the competitor, now must evaluate whether sufficient Available Transfer Capability will be available to honor its competitor's request. Although the formula for calculating Available Transfer Capability is required to be public, the transmission provider has the sole responsibility for, and a great deal of discretion in, its calculation, and will be very conservative in its estimates of expected contingencies, outages and the like. In this example, the transmission provider assumes two generating units will be unavailable, reducing Available Transfer Capability below the level where the requested transmission can occur, so it denies the request for summer service. But after the competitor's request is denied, the transmission provider's affiliate can ask in May for weekly firm service over the summer. So, when the affiliate's request is made, it is granted. Discretion on the part of the transmission provider in calculating Available Transfer Capability coupled with the affiliate's knowledge of how the calculations work enable the affiliate to secure the necessary firm service and win the sale opportunity.

Discretionary Use of TLRs

The following is another example derived from informal, non-public inquiry by the Commission regarding how TLRs are used.[2]

The facts: There are three neighboring, interconnected transmission systems, WestCo, CentralCo, and EastCo. (Their relative locations match their names).

CentralCo has 10,000 MW of generation and 8,000 MW of load west of a constrained line that divides its system. The line is limited to 1,500 MW of transfer capability. CentralCo has 1,000 MW of generation and 2,000 MW of load east of the constraint. Its cost of generation on either side of the constraint is comparable, and averages about $25 per MWh.

Under its normal dispatch pattern, CentralCo would generate 1,000 MW from its generation in the east to serve the eastern load, and would generate 9,000 MW from its western generation, 8,000 MW to meet its western load and 1,000 to meet the remainder of the 2,000 MW load in the east. This means that 1,000 MW of generation would usually flow across the constrained line for CentralCo to meet its own load, leaving 500 MW of west-to-east ATC on the constrained line.

NewGen, a generator located in WestCo's service area, wants to sell 100 MW for one day to a buyer in EastCo's service area. NewGen's cost of generation is $22 per MWh.

To make the sale, NewGen must secure 100 MW of transmission across CentralCo's system (including the constrained line), to make the sale. Therefore, NewGen requests transmission service through CentralCo's system. Under normal operating conditions, CentralCo's constrained line has available 500 MW of Available Transfer Capability, leaving plenty of transfer capability to accommodate the sale. Since its OASIS lists 500 MW of Available Transfer Capability, CentralCo grants the request.

If CentralCo were an RTO, it would have no financial interest in which generator makes any particular sale, and would focus on ensuring optimal and reliable system operation. Thus, it would dispatch the system to ensure that the 100 MW NewGen transaction would flow, since it could do so while still optimizing the dispatch of the CentralCo generators. But CentralCo has a financial incentive to block the NewGen transaction in order to make the sale itself and it has the information to make it happen. CentralCo, as transmission provider, knows the flow patterns on its system and the identity (and affiliation) of all generators flowing power on its system. This means that CentralCo's transmission arm would not need to engage in any prohibited off-OASIS

[1] Because this example is based on non-public inquiries, we have not identified the companies.

[2] Because this example is based on non-public inquiries, we have not identified the companies.

communications to dispatch the system in a way that favors its own affiliate.

CentralCo can block a portion of the competitor's transaction by changing its own dispatch pattern and declaring a TLR across the constrained line. CentralCo would reduce generation on the east side to 500 MW and increase generation from the west by the same amount to meet the eastern load. This would increase its own use of the constrained line to 1,500 MW which, in addition to the 100 MW of scheduled use by NewCo, would exceed the thermal limits of the line. CentralCo, as security coordinator for its own system, has great discretion as to when and for how long to declare a TLR across the constrained line. In this situation, rather than redispatching its own generators to accommodate NewGen's transaction, it could declare a TLR and curtail a portion of the NewGen's transmission transaction.

By curtailing transmission for a portion of the competitor's sale, this TLR allows CentralCo to step in to provide EastCo's needed 100 MW (following NewCo's transmission curtailment), possibly at an inflated price due to the TLR and the buyer's need to immediately secure replacement power.

The Commission is concerned that the use of emergency procedures offers opportunities for discrimination. A high incidence of TLRs reduces certainty in the market because it frustrates the expectations of bulk power sellers and their customers.[3] In turn, it provides a disincentive for market participants to take transmission risks and decreases overall liquidity in the transmission market.[4] The practice of using TLRs to manage congestion contributes to transmission and energy prices that are not just and reasonable and must be remedied.

Lack of Common Set of Rules Governing Transmission

1. Balancing Authority

A market participant that operates a control area may derive a market benefit. The primary function of a control area operator is to maintain a balance between the energy coming onto the grid and the energy being taken off. The North American Electric Reliability Council (NERC) refers to this primary function as balancing and the responsible entity as the balancing authority.[5] The balancing authority has generating resources that it may call on for balancing but also may rely on a neighboring balancing authority for balancing energy, which it must pay back. The payback is typically accomplished by returning energy at a later time.

A transmission customer outside the organized spot market of an ISO or RTO is expected to keep its own grid energy inputs and withdrawals in balance. For example, the customer may be a municipal utility that buys 50 megawatts from noon to 1 o'clock to meet a load that is expected to hover around 50 megawatts at that hour. The transmission customer cannot achieve exact balance in part because retail loads are not completely predictable.[6] To the extent the customer does not achieve exact balance, the balancing authority supplies or absorbs energy for balancing, charging the customer for the energy. For an excessive deviation from the scheduled amount of energy delivery, the transmission customer may have to pay a penalty rate under the public utility's tariff, intended to encourage good scheduling behavior so as to maintain reliable system operation.

A balancing authority outside an RTO or ISO is today typically also a market participant that serves its own power customers. In most cases, it is a large vertically integrated public utility that generates and buys power to meet the power needs of its native load. Such a balancing authority may be able to lower the cost of acquiring balancing energy and achieve a competitive advantage over other market participants that do business on its transmission system. It can rely on a neighboring balancing authority to loan it energy without having to pay for the energy. Further, it may avoid a penalty for excessive deviation. It can later return the energy taken in kind to the neighboring authority and may thus face a lower balancing cost than other energy providers. Although this problem may incur infrequently, it results in an undue cost preference for the investor-owned utility and its customers vis-a-vis the costs that other energy providers incur and pass on to their customers.

NERC has recognized a related reliability problem associated with excessive unplanned borrowing of energy in a highly competitive market and is in the process of writing new rules to alleviate this problem.[7] Because compliance with NERC's rules is voluntary, one NERC region filed on behalf of the public utilities in its region so that its rule relating to balancing would be mandatory. On May 31, 2000, the Commission approved a tariff filed by the East Central Area Reliability Council, which is the NERC regional reliability council for an area centered around Indiana, Ohio, and western Pennsylvania.[8] The tariff, designed to maintain reliability in an increasingly competitive region, is intended to eliminate any economic incentive that may exist under current reliability rules for a particular balancing authority to borrow large amounts of energy from neighboring authorities when the price of power is high and return it in kind when the price is low.[9] It does not, however, fully eliminate the economic advantage that a balancing authority that is also a market participant may have over other energy suppliers.

The Commission, in the proposed rule leading to Order No. 2000, using the then-current terminology of the control area operator, said that, in an RTO,

> unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not.[10]

The Commission concluded in Order No. 2000 that

> control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory.[11]

The Commission has not addressed this issue generically, however, for public utility transmission providers that are not in an RTO. There is a need for a tariff that addresses this issue explicitly for all public utility transmission providers.

2. Receipt and Delivery Point Flexibility

The Order No. 888 *pro forma* tariff provides nondiscriminatory rules governing the designation of receipt points, where power enters the transmission provider's system, and delivery points, where power exits the system. There are different such rules for network integration and point-to-point transmission customers, as required by the Order No. 888 *pro forma* tariff. Transmission customers say that these tariff provisions allow a vertically integrated public utility with a native load to provide itself with greater flexibility regarding designation of receipt and delivery points through practices that have become known in the industry as ''parking'' and ''hubbing.''

[3] *See* Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), *available in* <*http://www.ferc.gov/electric/bulkpower/midwest.pdf*>, at 2–32. See Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), *available in* <*http://www.ferc.gov/electric/bulkpower/southeast.pdf*>, at 3–38.

[4] *See* Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), *available in* <*http://www.ferc.gov/electric/bulkpower/midwest.pdf*>, at 2–33 (reporting eroded confidence and decreased liquidity in the Midwest market).

[5] Because most transmission systems were operated by vertically integrated utilities that performed many types of control functions, the term ''control area operator'' now lacks precision regarding which of these functions is being referred to in a particular context. Recently, NERC adopted new terminology for use in rewriting its reliability standards. It is eliminating the terms ''control area'' and ''control area operator'' and replacing these with several other terms that describe more precisely the functions performed. NERC refers to the entity responsible for maintaining system frequency by arranging for generation to balance load as the ''balancing authority.'' It is this function that is the subject of the first example. See The NERC Functional Model: Functions and Relationships for Interconnected Systems Operation and Planning (visited June 11, 2002) <*http://www.ferc.gov/Electric/RTO/mrkt-strct-comments/02–19–02/CACTR-Final-Report-Functional-Model.pdf*> for more information on the NERC functional model. *See also* Transcript of Assignment of RTO Characteristics and Functions Technical Conference, Docket No. RM01–12–000, at 12–34 (Feb. 19, 2002).

[6] A customer can achieve such balance through dynamic scheduling, which effectively takes it out of the control area.

[7] *See, e.g.*, Board of Trustees Meeting Highlights (visited May 31, 2002) <*http://www.nerc.com/pub/sys/all_updl/docs/bot/bot0106h.pdf*>

[8] *See* East Central Area Reliability Council, 91 FERC ¶ 61,197 (2000).

[9] *See id.* at 61,693–94.

[10] Order No. 2000 at 31,142.

[11] *Id.*

To illustrate, a point-to-point transmission customer, such as a power marketer, may be required to reserve transmission for a complete transaction, that is, from an actual generator to an actual power-consuming load. If it is announced today, for example, that generation will be available tomorrow from a particular generator, the marketer may be able to buy the power but unable to reserve the transmission if it has not yet identified a buyer and named its location on the grid. That is, it can name a point of receipt but cannot yet name a point of delivery, so it may be denied a reservation for firm transmission service.

A vertically integrated transmission provider with a native load, however, can buy the power from the same generator, naming that generator as the point of receipt and its native load network as the point of delivery, saying it intends to reduce its own generation to meet its native load power needs. The transmitting public utility is given a transmission reservation. Later, the public utility can find a buyer for the power and say it is making a sale from its freed-up generation, designated as the point of receipt, to the buyer's point of delivery—taking a second transmission reservation for the same power. In effect, the public utility will have reserved transmission for a purchase from the generator and a sale to the buyer in a manner that is not available to the marketer. The public utility is said to have ''parked'' the power at its native load location while it sought a buyer for the power. Parking can also occur if the buyer is known and transmission to the buyer is reserved, allowing the public utility time to search for a seller to match the buyer's power needs. The time delay involved in parking affords flexibility to a vertically integrated transmission provider that is not available to all transmission customers.

''Hubbing'' is similar but does not necessarily involve a time delay. Instead, it involves having more than one seller or more than one buyer, or both. Using the method just described for parking, a transmitting public utility with a native load may reserve transmission to buy power from several sellers and to sell power to several buyers. In effect, it may use its combined native load transmission network location as a hub for trading. It may acquire a portfolio of generators from which to obtain power to meet the power needs of a collection of power buyers, without having to match individual buyers and sellers. This hubbing allows the public utility to capture market efficiencies by combining resources to satisfy collective needs, and to gain a competitive advantage over others who cannot establish a hub because they are required by Point-to-Point Transmission Service rules to match a particular generator with a particular load for each transmission reservation.

This example shows another undesirable difference between two transmission services available to both wholesale and unbundled retail customers, Network Integration Transmission Service and Point-to-Point Transmission Service.

Today, the Commission concludes that the inherent differences in flexibility between the two types of tariff services, including the one described above, are resulting in undue preferences and thereby impeding the most efficient trading of power over the interstate transmission grid. Accordingly, the Commission proposes to create a single transmission service and equalize the playing field so that all transmission customers can park, hub or exercise equal creativity and flexibility in structuring transactions and serving customers.

3. Transmission Transfer Capability Set Aside for Reliability

Transmission transfer capability may be set aside by the transmission provider for either of two reliability-related reasons. One relates to the reliability of the transmission system itself and the other relates to generation reliability. As an example of the first, the power loading on a transmission line may be less than the line's capacity so that it can take up the power flows it must absorb if a parallel line should go out of service. The industry refers to this type of unused transmission capacity as a transmission reliability margin, or TRM. While reliability rules forbid a transmission provider from loading a line beyond its reliability limit, these rules are not necessarily mandatory or enforceable. However, there have been few complaints about discriminatory violations of TRM reliability limits.

Most complaints have related to transmission transfer capability that is set aside to provide for adequate generation. A vertically integrated public utility may have decided in the past that, to achieve adequate generation resources (including reserves), it was more economical to build stronger transmission interconnections with neighbors that could share their extra generation when needed than to build extra generation in its own service area. When Order No. 888 was under consideration, such utilities argued that some transmission transfer capability should be set aside for this generation reliability function.[12] They asserted that, if others were allowed to purchase firm rights to this transmission capability, it would not be available to the public utility when needed for the generation reliability purpose for which it was built.[13] The term used for this type of transmission set aside is capacity benefit margin (CBM). Order No. 888 permitted utilities to have CBM if they fully explained and justified the amount set aside.[14] The CBM set-aside practice is not used universally; some utilities do not claim a capacity benefit margin. Moreover, where it is used, there is regional variation in its implementation.

Since Order No. 888 issued, at least two issues related to CBM have been controversial. One is whether all network transmission customers, including for example municipal utilities within the transmission owner's service territory, have an equal opportunity to set aside transmission for this purpose. The second is whether those who set aside transmission for CBM are reserving it and paying for it under the terms of the *pro forma* tariff.

[12] *See* Order No. 888 at 31,693–94.

[13] *See id.*

[14] *See id.* at 31,694.

The second issue is best explained with an example. Suppose a transmission-owning public utility sets aside 100 MW of transfer capability at its interface with a neighboring utility to help ensure adequate generation for the public utility's native load customers. Suppose further that the public utility's native load is 600 MW, and the collective amount of point-to-point transmission customer imports is 200 MW and the line's total capacity is 900 MW. Under the usual method of allocating transmission costs to customers, the point-to-point customer would pay for and receive 200 MW of transmission service and the public utility would pay for 600 MW of transmission system cost but receive 600 MW of transmission service and 100 MW of reserved capacity. In some cases, the transmission provider's merchant affiliate has used the CBM set-aside on a non-firm basis to make sales without paying for the transmission capacity used.

In 1998 the Commission received complaints alleging that some transmission-owning utilities were inappropriately reducing Available Transfer Capability to reflect transmission reliability requirements and capacity benefit margins.[15] The Commission observed in *WPPI* that the determination of CBM was made differently in the Available Transfer Capability calculations of various utilities and was not explained in one tariff.[16] The Commission stated that it was ''concerned that the exercise of this discretionary adjustment can turn on considerations (such as the reduction of power supply costs and limiting the generation supply options of competitors) that involve the transmission provider's merchant arm rather than its transmission function.'' [17]

In 1999, the Commission initiated a generic inquiry into policies for transmission reliability set-asides. In particular, the Commission convened a conference in May 1999 in which it examined the practices of use, and the alleged abuses, of CBM.[18] Transmitting utilities had been accused of using CBM designations to withhold transmission transfer capability from the wholesale electric transmission market. The Commission also requested comments on the subject. One commenter stated:

Even NERC acknowledges that there is a wide disparity in the magnitudes of TRM [transmission reliability margin] and CBM applied by transmission providers across an interconnection, especially in the quantification of CBM. The reason for this disparity is the absence of an enforceable industry standard—or more appropriately, a Commission rule—for the definition of CBM.[19]

[15] *See Wisconsin Public Power Inc. SYSTEM.* v. *Wisconsin Public Service Corporation, et al.*, 83 FERC ¶61,198 (1998) [hereinafter *WPPI*].

[16] *See id.* at 61,857–58.

[17] *Id.* at 61,858.

[18] *See* Capacity Benefit Margin in Computing Available Transmission Capacity, 64 Fed. Reg. 16730–31 (March 31, 1999), 86 FERC ¶61,313 (1999), (hereinafter CBM Notice).

[19] The Electricity Consumers Resource Council and the American Iron and Steel Institute (Industrial Consumers), Docket No. EL99–46–000, written comments at 3 (footnote omitted).

In July 1999, the Commission issued an order clarifying the method for computing ATC, including provisions dealing with CBM.[20] There, the Commission stated that: ''[t]he measures that we are requiring transmission providers to take at this time consist of short-term solutions, which, for now, take no position on the transmission provider's ability to set aside CBM for generation reliability requirements.''[21] The Commission acknowledged that NERC had already started a process to establish a standardized methodology for deriving CBM, and directed public utility transmission providers, working through NERC, to complete this process by the end of 1999.[22]

NERC called on each region to develop and document its own methodologies and guidelines for determining TRM and CBM.[23] It reported that its ATC Working Group was continuing to develop CBM and TRM, and that the draft standards would require each region to develop a region-wide CBM methodology.[24] It also noted that many methods for calculating CBM were used by transmission providers within each region.[25] Although a single North American standard CBM method was called for by transmission customers, NERC reported that it was not able, at that time, to develop such a standard for CBM.[26] NERC noted that the consideration of a standard CBM method would follow the completion of regional methods,[27] a process that is still ongoing.

The lack of standards for TRM and CBM impedes the development of basic information required by Order Nos. 888 and 889 as a basis for eliminating undue discrimination in the provision of interstate transmission services. Further impeding competition is continued uncertainty about whether and how to account for CBM in determining ATC and how CBM costs should be allocated. The industry needs Commission guidance to achieve standardization in these areas.[28]

4. Transmission Curtailment Preference for Bundled Retail Load

The Commission continues to receive complaints that transmission service to deliver power to bundled retail customers continues to be superior to transmission services for wholesale and unbundled retail transmission customers. In *Northern States Power Company (NSP)*, the United States Court of Appeals for the Eighth Circuit held that the Commission had exceeded its authority when it rejected proposed transmission curtailment provisions, contained in a public utility's wholesale open access transmission tariff, that favored the utility's retail customers over its wholesale customers.[29] On remand, the Commission permitted NSP to amend its open access transmission tariff to reflect its proposed transmission curtailment procedures to be effective in the ''rare circumstances'' where generation redispatch is inadequate or unavailable to fully relieve the transmission constraint.[30] However, the Commission also told NSP that if it amends its tariff to reflect its proposed transmission curtailment procedures, ''NSP must revise its rates for firm point-to-point transmission service * * * to recognize the inferior quality of that service compared to the service provided by NSP to its native load and network customers. * * *''[31]

Although NSP later withdrew its objection to equal transmission curtailment treatment for all transmission customers, the case points out a difficulty the Commission has in ensuring transmission access that is not unduly discriminatory for all transmission customers—retail and wholesale—unless all transmission customers take service under the same tariff.

Seams Problems. Even apparently minor differences in rules can create seams problems. The three Northeastern ISOs, which have substantially similar market designs and transmission congestion management systems, have struggled to coordinate their rules to lower trading barriers, but have achieved only limited success after several years. If each RTO in the Nation were to implement different rules, processes, and market mechanisms, these differences combined could produce and exacerbate significant barriers to transmission and electric power sales in interstate commerce.[32]

As an example of a specific seams problem, incompatible ramping rules have made power sales among the ISO systems in the Northeast unnecessarily difficult and prevented some trades. Among the operating protocols of a transmission provider are rules for increasing and decreasing the power output of a generator (called ''ramping'') connected to the transmission system. To implement a transaction between two systems, generation in the supplying system must be increased, or ''ramped'' up, and generation in the receiving system must be decreased, or ''ramped'' down. The ramping up and ramping down in the two systems should begin at the same time, last for the same length of time, and end at the same time. But different systems can have different rules about the timing and rate of ramping. For example, PJM allows ramping to occur every fifteen minutes; it can occur, for example, at 1 p.m., 1:15 p.m., 1:30 p.m, 1:45 p.m., 2 p.m., and so forth. New York and New England require ramping to occur on the hour, at 1 p.m or 2 p.m. but not within an hour. Thus, PJM's ramping rules permit a sale from PJM to New York to begin on the half hour by ramping up generation in PJM, but New York's ramping rules do not allow a buyer in New York to receive the power because it cannot ramp down generation on the half hour. Also, systems may place different limits on the amount of ramping that may occur on the interface with a neighboring system. Then, one system may allow an amount to be exported that the neighbor will not allow to be imported.[33] These differences must be reconciled to maximize opportunities for constructive trade at minimal transaction costs and obstacles.

Several efforts are underway at the Commission or within the industry to address seams problems and the

[20] Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶61,099 (1999).

[21] *Id.* at 61,237. The order, among other things, also directed each transmission provider to post specific CBM information and practices on its OASIS site within 30 days of the order, and to reevaluate generation reliability needs periodically so as to make known the availability of CBM capacity to others. *See id.*

[22] *See id.* at 61,238.

[23] *See* Response of the North American Electric Reliability Council to the CBM Order, Docket No. EL99–46–000 (Aug. 12, 1999), at 3.

[24] *See id.* at 3–4.

[25] *See id.* at 5.

[26] *See id.*

[27] *See* Letter from Virginia C. Sulzberger, North American Electric Reliability Council, to David P. Boergers, FERC, Docket No. EL99–46–000 (Dec. 23, 1999), at 2. There have been no further Commission proceedings on a generic basis addressing CBM. Parties did raise the CBM issue in the proceedings leading to Order No. 2000, but the Commission determined that ''[t]hese issues are too detailed for this proceeding and we will not address them at this time.'' Order No. 2000 at 31,146. Development of methods for calculating ATC and CBM at NERC are continuing.

[28] Addressing the topic of ATC coordination, which includes the ''[p]roper quantification of transmission reliability margin (TRM)'' the NERC ATC Coordination Task Force concluded that:

The existing definition of ATC coordination does not meet the needs of all members of the marketplace (all market participants) because there are too many diverse opinions that will not allow for consensus. * * * It is impossible to meet the existing definition of coordination due to differing market objectives, and regional business practices and transmission provider tariffs, and corporate objectives. Until these issues are resolved, coordination will not occur. Available Transfer Capability Coordination Task Force, *ATC Coordination and Related Issues* at 8–9 (July 12, 2000), *available in ftp://www.nerc.com/pub/sys/all__upoll/pc/minutes/ac–0007m.pdf.*

[29] *Northern States Power Company, et al.* v. *Federal Energy Regulatory Commission,* 176 F.3d 1090, 1096 (8th Cir. 1999), *cert. denied sub nom.* Enron Power Marketing, Inc. v. Northern States Power Company, 528 U.S. 1182 (2000).

[30] *See* Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin), 89 FERC ¶ 61,178 at 61,552–53 (1999). Subsequently, the Commission has applied *NSP* narrowly and indicated that it continues to believe that it has the authority to treat such customers comparably. *See* North American Electric Reliability Council, *et al.,* 96 FERC ¶ 61,079 at 61,345 (2001).

[31] 89 FERC at 61,553.

[32] For perspectives on this topic and its possible economic consequences, *see* Mirant Corporation, *Northeast Power Markets: The Argument for a Unified Grid,* 139 Public Utilities Fortnightly, at 36–45, Sept. 1, 2001. See *also* Hartshorn, Andrew P. and Harvey, Scott M., Assessing the Short-Run Benefits from a Combined Northeast Market, LECG, LLC, October 23, 2001.

[33] An extensive list of seams issues, ISO rule differences, and a discussion of efforts to reduce seams problems among the Northeast systems is available at the ISO Memorandum of Understanding Web site. *See* Seams Issues—High Priority Items *http://www.isomou.com/working__groups/business__practices/documents/general/bpwg__matrix.pdf*≤. At the June 12, 2002 Commission meeting, New York ISO presented a list of 40 seams issues in the Northeast and a time line for resolving these issues. *See* Transcripts of Commission Meetings, June 12, 2002, *available in http:www.ferc.gov/calendar/commissionmeetings/transcripts.htm.*

development of standards. The Commission issued a Notice of Proposed Rulemaking to standardize rules for interconnecting generators to the grid.[34] The Commission also issued an Advanced Notice of Proposed Rulemaking to extend the standardization requirements of Order No. 889 to include electronic scheduling, among other matters.[35] In response to the latter, the industry formed the Electronic Scheduling Collaborative (ESC) to develop recommendations for the proposed rule but reported that the diversity of business, operating and other practices around the country made it very difficult to develop standards and protocols for electronic scheduling that would apply to all public utility systems. In its October 5, 2001 report to the Commission, the Electronic Scheduling Collaborative identified ten key policy issues that would give significant impetus to standards development. All of these issues are addressed in this proposed rule. NERC is working to achieve more uniform and enforceable reliability rules, and the North American Energy Industry Standards Board was formed in the autumn of 2001 in part to develop standards for electric wholesale business practices and communications protocols. Regional groups have formed to address seams issues, including the Seams Steering Group for the Western Interconnection and a Memorandum of Understanding among the three Northeast ISOs and the Ontario Independent Market Operator to address seams issues. In the Midwest, over the last several years various groups have met to deal with seams issues between two or more proposed RTOs for the central United States. The Tennessee Valley Authority (TVA) has also negotiated memoranda of understanding with Midwest Independent System Operator, Entergy and Southern Companies to pursue development of a coordination agreement to address seams issues in the Southeast. In its RTO orders, the Commission has been concerned about seams between neighboring RTOs with different rules, and also about seams between entities that are part of one large RTO.[36]

Many panelists at the Commission's seams conference urged us to develop standards for RTOs before they begin operating—indeed before they invest heavily in software development for a unique set of regional transmission rules and market designs.[37] This urging played a significant role in the genesis of this rulemaking.

Another seams problem can arise from different market price mitigation rules in neighboring regions. When western electric power prices were high in 2001, for a short time the Commission applied price mitigation to certain generators in California for spot market sales of power within California.[38] But these mitigation measures did not apply to sales from these generators to buyers outside California. As a result, some California generators sold power to parties outside California, that sold the power back into the state without facing the same price mitigation rule, a practice that was dubbed ''megawatt laundering.'' The Commission shortly thereafter applied uniform mitigation measures throughout the United States portion of the Western interconnection to remedy this problem. Uniformity of rules eliminated the seams problem in that circumstance.[39]

Market Design Flaws. The ISO markets have experienced numerous design flaws. A few of the more fundamental flaws are detailed below:

1. *Transmission Congestion Pricing by Zones Rather than Nodes.* On all single utility transmission systems, the cost of congestion is allocated to all users of the grid on a load ratio share basis. ISOs have tried various ways to allocate these costs to the customer or customers whose transactions caused the congestion. Several ISO markets attempted to price transmission congestion based on the average cost of congestion for transfers of power between defined zones on the system, rather than pricing the transmission congestion on a point-to-point basis. The zonal method tries to allocate congestion costs without too much pricing complexity. The theory of the method is that zones can be established within which little transmission congestion will occur (if any congestion does occur within the zone, all customers receiving power within the zone must share the cost of congestion). Variants of zonal pricing were tried in California, PJM, Texas (ERCOT) and New England.[40] In all cases the methods contained a similar flaw: using the zonal price signal did not induce short-term efficiency in the region, and it spread the congestion costs too broadly to clearly identify the transactions causing the congestion or the location of the structural fixes necessary to resolve it. It has also been difficult to determine in advance the appropriate zones, as flows have changed after restructuring.[41]

2. *Overly Restrictive Ancillary Service Market Designs.* Although the specific designs were different, both the California ISO and ISO New England initially attempted to require sellers to separately bid into each of several ancillary services markets. The hope with this design was to establish vibrant markets for each of the various ancillary services. However, the market design did not allow the substitution of a higher quality product (operating reserve—spinning) for a lower quality product (operating reserve—supplemental), even if the higher quality product was available at a lower price. This resulted in thin markets for certain ancillary services because sellers had no incentive to offer in one market if another market paid more. The perverse result was that lesser quality product markets (such as operating reserve—supplemental) cleared at higher prices than higher quality products (operating reserve—spinning). Sellers had to guess, based on limited information, which service would be the most highly valued. The market design failed to recognize that certain ancillary services were substitutes, *e.g.,* spinning reserves can ''provide'' supplemental reserves because operating reserves—spinning are more responsive to the ISO's dispatch signal. This design flaw created artificial barriers to entry for certain products, increasing market power and inefficiency, causing customers to pay prices higher than necessary for ancillary services.[42]

3. *The Absence of a Day-Ahead Market.* Certain ISO markets, including PJM and ISO New England, began operations with only real-time energy markets. All prices for power sold through the balancing market and ancillary service markets were cleared based on schedules and actual purchases in real time. In all cases, ISOs with only a real-time market concluded that a day-ahead market settlement system was also needed so that transmission customers could better protect against congestion costs, and so buyers and sellers of energy too could better protect against energy price uncertainty.[43] A day-ahead market enhances reliability because it allows the system operator to assess the next day's likely load and available resources. The California ISO has had difficulty operating the system reliably since the California PX ceased operations. A financially binding day-ahead market serves a critical reliability function by facilitating planning, unit scheduling, and load balancing.

Appendix D—Conversion of the Order No. 888—A *Pro Forma* Tariff to the Revised Standard Market Design *Pro Forma* Tariff

The following outlines the Order No. 888–A *pro forma* tariff and indicates where the various sections appear in the SMD Tariff. Where there are modifications or additions, they are identified and described. In addition, throughout the SMD Tariff, we have revised our terminology to match the new NERC terminology.

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[34] *See* Standardization of Generator Interconnection Agreements and Procedures, 62 Fed. Reg. 22,249 (May 2, 2002), FERC Stats. & Regs. ¶ 32,560 (2002).

[35] Open Access Same-Time Information System (Phase II), Docket No. RM00–10–000, Advance Notice of Proposed Rulemaking, 92 FERC ¶ 61,047 (July 14, 2000).

[36] *See* Alliance Companies, *et al.,* 97 FERC ¶ 61,327 at 62,530 (2001).

[37] Conference on RTO Interregional Coordination, Docket No. PL01-5-000, June 19, 2001.

[38] *See San Diego Gas & Electric Company* v. *Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange, et al.,* 95 FERC ¶ 61,115 (2001). The Commission's order on price mitigation provided in part that certain California generators that had not already sold their power were required to bid into the ISO's real-time market at a constrained bid price.

[39] *See* New York Independent System Operator, Inc., *et al.,* 92 FERC ¶ 61,073 (2000); *NSTAR Services Company* v. *New England Power Pool, et al.,* 92 FERC ¶ 61,065 (2000); and PJM Interconnection, L.L.C., 96 FERC ¶ 61,233 (2001) (orders accepting a uniform $1000 bid cap).

[40] *See* New England Power Pool, 88 FERC ¶ 61,147 (1999); PJM Interconnection, LLC, 81 FERC ¶ 61,257 (1997), *order on reh'g,* 92 FERC ¶ 61,282 (2000); Order Proposing Remedies for California Wholesale Electric Markets, 93 FERC ¶ 61,121 (2000).

[41] This zonal cost allocation for congestion management is different from and should not be confused with proposals to aggregate energy prices at several points into hubs.

[42] *See* AES Redondo Beach, L.L.C., *et al.,* 84 FERC ¶ 61,046 (1998); New England Power Pool, 85 FERC ¶ 61,379 (1998).

[43] *See* PJM Interconnection, LLC, 91 FERC ¶ 61,148 (2000); New England Power Pool, *et al.,* 96 FERC ¶ 61,317 (2001).

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
I. COMMON SERVICE PROVISIONS	Part I
1 Definitions	A.1
[revised to include new transmission service, LMP, Congestion Revenue Rights, and market services]	
2 Initial Allocation and Renewal Procedures	revised
2.1 Initial Allocation of Available Transmission Capability	deleted
[the section was for the initial conversion to an open access tariff; it is no longer needed]	
2.2 Reservation Priority for Existing Firm Service Customers	B.12
[Revised to reflect transition to Congestion Revenue Rights. Ensures that existing customers keep the right to roll over long-term firm service until implementation of the Congestion Revenue Rights auction (B.12.1)]	
3 Ancillary Services	C
[Slight modification to definitions to match best practices of the Northeast ISOs]	
3.1 Scheduling, System Control and Dispatch Service	C.1
3.2 Reactive Supply and Voltage Control From Generation Sources Service	C.2
3.3 Regulation and Frequency Response Service	C.3
3.4 Energy Imbalance Service	C.4
[imbalances will be priced at real-time LMP price, making deviation band and delayed (30 days) resolution unnecessary]	
3.5 Operating Reserve—Spinning Reserve Service	C.5
3.6 Operating Reserve—Supplemental Reserve Service	C.5
4 Open Access Same-Time Information System (OASIS)	A.2
5 Local Furnishing Bonds	A.3
5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds	A.3.1
[reflects that Transmission Owner will not be the Transmission Provider; also modified to define the applicable provisions of the Internal Revenue Code; and to add language from the preamble of Order No. 888–A clarifying that this provision also applies if a customer requests service that would jeopardize the tax-exempt status of bonds used to finance the transmission provider's generation or distribution facilities, even if no transmission facilities were financed with such bonds]	
5.2 Alternative Procedures for Requesting Transmission Service	A.3.2
[modified to make transmission provider advise the customer of expected costs resulting from loss of tax-exempt status within thirty days of receipt of an application for service. Also modified to clarify that any Commission order issued pursuant to section 211 of the FPA would specify that service under this section is provided subject to the customer's payment of all costs deemed eligible for recovery]	
6 Reciprocity	A.4
7 Billing and Payment	A.5
7.1 Billing Procedure	A.5.1
7.2 Interest on Unpaid Balances	A.5.2
7.3 Customer Default	A.5.3
8 Accounting for the Transmission Provider's Use of the Tariff	deleted
[no longer needed as Transmission Provider is an independent entity—transmission owners that are load-serving entities will now take service under the revised tariff]	
9 Regulatory Filings	A.6
10 Force Majeure and Indemnification	A.7
10.1 Force Majeure	A.7.1
10.2 Indemnification	A.7.2
11 Creditworthiness	A.8
12 Dispute Resolution Procedures	A.10
12.1 Internal Dispute Resolution Procedures	A.10.1
12.2 External Arbitration Procedures	A.10.2
12.3 Arbitration Decisions	A.10.3
12.4 Costs	A.10.4
12.5 Rights Under the Federal Power Act	A.10.5
Additions to Part I of the Tariff	
(1.11) Eligibility for Transmission Provider Services	A.9
[replaces definition of Eligible Customer so that "Customer" could apply to transmission and market services]	
—Data and Confidentiality Provisions	A.12
[ensures that Transmission Provider and market monitoring unit have access to operational and bid data; additional changes to ensure Commission access to data for investigations]	
II. POINT-TO-POINT TRANSMISSION SERVICE	
[PTP service replaced by Network Access Service. Section replaced entirely (except as noted) by Network Access Service—many provisions here that are comparable to Network Integration Transmission Service retained]	
Preamble	
13 Nature of Firm Point-To-Point Transmission Service	
13.1 Term	B.2.2.1.(vi)
[modified to be as short as one hour of service]	
13.2 Reservation Priority	deleted
[first-come, first served priority system replaced with LMP, "who values it the most" system of rationing capacity]	
13.3 Use of Firm Transmission Service by the Transmission Provider	deleted
["Transmission Provider" will take service under a service agreement like all other customers]	
13.4 Service Agreements	B.2.5
[modified for Network Access Service]	
13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs	
13.6 Curtailment of Firm Transmission Service	deleted
[use NITS procedures]	

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
13.7 Classification of Firm Transmission Service	
13.8 Scheduling of Firm Point-To-Point Transmission Service	B.2.10
[revised to incorporate scheduling through the Day-Ahead and Real-Time markets]	
14 Nature of Non-Firm Point-To-Point Transmission Service	deleted
[all scheduled service is firm under Network Access Service]	
15 Service Availability	
15.1 General Conditions	B.5.1
15.2 Determination of Available Transmission Capability	B.5.2
15.3 Initiating Service in the Absence of an Executed Service Agreement	B.2.9
15.4 Obligation To Provide Transmission Service That Requires Expansion or Modification of the Transmission System.	B.5.9
15.5 Deferral of Service	
15.6 Other Transmission Service Schedules	B.13
[modified to add service continues until contracts ''expire or'' are modified by the Commission]	
15.7 Real Power Losses	B.10.3.2
[revised to reference markets and cost of marginal losses]	
16 Transmission Customer Responsibilities	B.8
16.1 Conditions Required of Transmission Customers	B.8.1
16.2 Transmission Customer Responsibility for Third-Party Arrangements	B.8.2
17 Procedures for Arranging Firm Point-To-Point Transmission Service.	
17.1 Application	deleted
[Network Access Service will use comparable NITS procedures]	
17.2 Completed Application	B.2.2.1
[section retained with minor modifications in order and to establish minimum term of service of one hour; questions in preamble ask whether different procedures should be used by load-serving entity customers (who have load and/or generation and transmission facilities and need integration service) and non-load-serving entity transmission customers (who do not)]	
17.3 Deposit	B.2.2
17.4 Notice of Deficient Application	B.2.6
17.5 Response to a Completed Application	B.2.7
17.6 Execution of Service Agreement	B.2.8
17.7 Extensions for Commencement of Service	deleted
[related to PTP reservations which will not be used by Network Access Service]	
18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service	deleted
[all scheduled Network Access Service is firm]	
19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests	
19.1 Notice of Need for System Impact Study	B.5.3
19.2 System Impact Study Agreement and Cost Reimbursement	B.5.4
19.3 System Impact Study Procedures	B.5.5
19.4 Facilities Study Procedures	B.5.6
19.5 Facilities Study Modifications	B.5.7
19.6 Due Diligence in Completing New Facilities	B.5.8
19.7 Partial Interim Service	B.5.10
19.8 Expedited Procedures for New Facilities	B.5.11
20 Procedures if the Transmission Provider Is Unable To Complete New Transmission Facilities for Firm Point-To-Point Transmission Service.	B.6
20.1 Delays in Construction of New Facilities	B.6.1
20.2 Alternatives to the Original Facility Additions	B.6.2
20.3 Refund Obligation for Unfinished Facility Additions	B.6.3
21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities	B.7
21.1 Responsibility for Third-Party System Additions	B.7.1
21.2 Coordination of Third-Party System Additions	B.7.2
22 Changes in Service Specifications	
22.1 Modifications On a Non-Firm Basis	deleted
[use NITS procedures]	
22.2 Modification On a Firm Basis	deleted
[use NITS procedures]	
23 Sale or Assignment of Transmission Service	D.3, 7, and 8
[revised—replaced with the resale of Congestion Revenue Rights]	
24 Metering and Power Factor Correction at Receipt and Delivery Points(s)	A.11
24.1 Transmission Customer Obligations	A.11
[revised—additional detail added consistent with New York ISO Market Services Tariff]	
24.2 Transmission Provider Access to Metering Data	A.11
[revised—additional detail added consistent with New York ISO Market Services Tariff]	
24.3 Power Factor	A.11
[revised—additional detail added consistent with New York ISO Market Services Tariff]	
25 Compensation for Transmission Service	deleted
[charges based on NITS rates and charges instead (Section 34)]	
26 Stranded Cost Recovery	deleted
[the Transmission Provider is now an independent entity; recovery of stranded costs remains permissible, but will no longer be part of the tariff]	
27 Compensation for New Facilities and Redispatch Costs	deleted
[assignment of redispatch costs replaced by LMP system]	
III. NETWORK INTEGRATION TRANSMISSION SERVICE	

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
[Replaced by Network Access Service; certain similar provisions retained and revised, as noted. Others added from PTP]	
Preamble	preamble
28 Nature of Network Integration Transmission Service	B.1
[revised to become Network Access Service]	
28.1 Scope of Service	B.1.1
28.2 Transmission Provider Responsibilities	B.1.3
28.3 Network Integration Transmission Service	deleted
[requires OATT service to be comparable to native load service; all service now the same by definition]	
28.4 Secondary Service	B.1.4
[revised to include Congestion Revenue Rights]	
28.5 Real Power Losses	B.10.3.2
[revised—losses can also be provided through the market]	
28.6 Restrictions on Use of Service	deleted
[no restrictions on service—third part sales must be PTP; now one service for all]	
29 Initiating Service	B.2
29.1 Condition Precedent for Receiving Service	B.2.1
29.2 Application Procedures	B.2.2.2
[section retained with minor modifications to establish minimum term of service of one hour; but questions in preamble ask whether different procedures should be used by load-serving entity customers (who have load and/or generation and transmission facilities and need integration service) and non-load-serving entity transmission customers (who do not)]	
29.3 Technical Arrangements To Be Completed Prior to Commencement of Service	B.2.3
29.4 Network Customer Facilities	B.2.4
29.5 Filing of Service Agreement	B.2.5
30 Network Resources	B.3
[section retained, but questions in preamble ask whether different procedures should be used by load-serving entity customers (who have load and/or generation and transmission facilities and need integration service) and non-load-serving entity transmission customers (who do not)]	
30.1 Designation of Network Resources	B.3.1
30.2 Designation of New Network Resources	B.3.2
30.3 Termination of Network Resources	B.3.3
30.4 Operation of Network Resources	B.3.4
30.5 Network Customer Redispatch Obligation	B.3.6
[redispatch obligation fulfilled through market structure—all generators will bid into market and follow Transmission Provider's dispatch instructions; section removes reference to Transmission Provider's own generation]	
30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With the Transmission Provider.	B.3.7
30.7 Limitation on Designation of Network Resources	deleted
[no limitations on amount of use of resources; any excess takes or deliveries priced at market clearing price]	
30.8 Use of Interface Capacity by the Network Customer	deleted
[customers can use as much interface capacity as they want as long as they are willing to pay congestion charges]	
30.9 Network Customer Owned Transmission Facilities	B.3.9
31 Designation of Network Load	B.4
[largely revised to remove the formal designation and replace with an identification of load and new loads]	
31.1 Network Load	B.4.1
31.2 New Network Loads Connected With the Transmission Provider	B.4.2
31.3 Network Load Not Physically Interconnected With the Transmission Provider	deleted
[required load on other systems to be counted as Network Load or served under PTP; now no charge for exports]	
31.4 New Interconnection Points	B.4.3
31.5 Changes in Service Requests	B.4.4
31.6 Annual Load and Resource Information Updates	B.4.5
32 Additional Study Procedures for Network Integration Transmission Service Requests	B.5
[now under Section 5, Service Availability. All sections modified to include requests for Congestion Revenue Rights]	
32.1 Notice of Need for System Impact Study	B.5.3
32.2 System Impact Study Agreement and Cost Reimbursement	B.5.4
32.3 System Impact Study Procedures	B.5.5
32.4 Facilities Study Procedures	B.5.6
33 Load Shedding and Curtailments	B.9
33.1 Procedures	B.9.1
[places curtailment procedures in the tariff rather than in Network Operating Agreements]	
33.2 Transmission Constraints	B.9.2
[narrows focus of section to address only constraints not first resolved by the LMP system]	
33.3 Cost Responsibility for Relieving Transmission Constraints	deleted
[load ratio share allocation of redispatch costs is replaced by LMP system]	
33.4 Curtailments of Scheduled Deliveries	B.9.3
[narrows focus of section to address only constraints not first resolved by the LMP system; gives priority to customers with adequate resources who are also using Congestion Revenue Rights (question in preamble on whether we should grant this priority)]	
33.5 Allocation of Curtailments	deleted

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
[revised to no longer refer to sharing of curtailments between Transmission Provider and other customers—all load-serving entities will now be customers]	
33.6 Load Shedding	B.9.4
[provision in tariff, not Network Operating Agreement; done on a non-discriminatory basis]	
33.7 System Reliability	B.9.5
[Transmission Provider can propose penalties for failure to follow a curtailment order]	
34 Rates and Charges	B.10
34.1 Monthly Demand Charge	B.10.1
[revised to only apply the load ratio share Access Charge to deliveries to load located on the Transmission Provider's system; through and out service customers would not pay the Access Charge unless they wanted to receive a direct allocation of Congestion Revenue Rights]	
34.2 Determination of Network Customer's Monthly Network Load	B.10.2
[would only include load located on the Transmission Provider's system]	
34.3 Determination of Transmission Provider's Monthly Transmission System Load	deleted
[this section accounted for PTP service, which will no longer exist—may still need a transitional calculation]	
34.4 Redispatch Charge	B.10.3
[revised to describe the Usage Charge, which consists of the congestion charge and the loss charge]	
34.5 Stranded Cost Recovery	deleted
[the Transmission Provider is now an independent entity; recovery of stranded costs remains permissible, but will no longer be part of the tariff]	
35 Operating Arrangements	B.11
35.1 Operation under the Network Operating Agreement	B.11.1
35.2 Network Operating Agreement	B.11.2
35.3 Network Operating Committee	B.11.3
SCHEDULE 1	
Scheduling, System Control and Dispatch Service	C.1
SCHEDULE 2	
Reactive Supply and Voltage Control From Generation Sources Service	C.2
SCHEDULE 3	
Regulation and Frequency Response Service	C.3
SCHEDULE 4	
Energy Imbalance Service	C.4
SCHEDULE 5	
Operating Reserve—Spinning Reserve Service	C.5
SCHEDULE 6	
Operating Reserve—Supplemental Reserve Service	C.5
SCHEDULE 7	deleted
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service	deleted
[all rates in Part VIII]	
SCHEDULE 8	deleted
Non-Firm Point-To-Point Transmission Service	deleted
[no non-firm service]	
ATTACHMENT A	
Form of Service Agreement for Firm Point-To-Point Transmission Service	Part VI
[name change for Network Access Service]	
ATTACHMENT B	
Form of Service Agreement for Non-Firm Point-To-Point Transmission Service	deleted
[no non-firm service]	
ATTACHMENT C	
Methodology To Assess Available Transmission Capability	Attachment A
[to be filed by Transmission Provider; must be done by an independent entity]	
ATTACHMENT D	
Methodology for Completing a System Impact Study	Attachment B
[to be filed by Transmission Provider]	
ATTACHMENT E	
Index of Point-To-Point Transmission Service Customers	Attachment D
[name change for Network Access Service]	
ATTACHMENT F	
Service Agreement for Network Integration Transmission Service	deleted
[one for all Network Access Service Customers—Part VI]	
ATTACHMENT G	
Network Operating Agreement	Attachment C
[to be filed by Transmission Provider]	
ATTACHMENT H	
Annual Transmission Revenue Requirement for Network Integration Transmission Service	Part VIII
[all rates addressed in Part VIII]	
ATTACHMENT I	
Index of Network Integration Transmission Service Customers	deleted
[one for all Network Access Service Customers—Attachment D]	
New Sections of the Pro Forma Tariff:	
Part II.D. Congestion Revenue Rights	
Part III. Day-Ahead and Real-Time Market Services	
Part IV. Market Monitoring	
Part V. Generation Interconnection Procedures	

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
[will be the outcome of the Standardization of Generator Interconnection Agreements and Procedures, Notice of Proposed Rulemaking, 99 FERC ¶61,086 (2002)]	
Part VI. Transmission Planning and Expansion	
Part VIII. Appendices (Details for calculation of rates and market clearing prices)	

Appendix E

Standard Market Design and Trading Strategies Encountered in the Independent System Operators

Currently, five ISOs operate organized markets for energy and ancillary services, California ISO, PJM, New York ISO, ISO-New England and ERCOT. This appendix discusses how Standard Market Design would handle various trading strategies that were allegedly used for market manipulation in these ISOs, including those described by Enron Corporation in two memoranda as being used in the California wholesale markets. Standard Market Design incorporates lessons we have learned from experience in these organized markets. In many cases the proposed market rules have been designed to avoid the market design flaws that were the basis for these trading strategies. For others, Standard Market Design relies on strong market monitoring by the Independent Transmission Provider's Market Monitoring Unit and the Commission Office of Market Oversight and Investigation to ensure compliance with the market rules and to detect new market manipulation strategies.

Enron Strategies and Standard Market Design

In memoranda dated December 6, 2000 and December 8, 2000, attorneys for Enron detailed various trading strategies that were being used in California wholesale markets. The strategies discussed in the Enron memoranda were mainly tailored to take advantage of flaws in the California market design, particularly its congestion management system. Standard Market Design uses a different congestion management system that would make most of these strategies infeasible.

Most of the strategies described in the Enron memoranda depended on the development of a day-ahead schedule for power sales that was developed without determining whether that day-ahead schedule was physically feasible. In real time, the California ISO made payments to entities to relieve congestion. This created an incentive for an entity to create congestion in the day-ahead schedule at no cost so that the same entity would be paid to relieve that congestion in real time.

Standard Market Design uses a nodal congestion management system, Locational Marginal Pricing (LMP) together with a physically feasible and financially binding day-ahead schedule. The use of a nodal congestion management system ensures that all transmission constraints are considered in developing day-ahead schedules and any congestion is reflected in the prices for energy and transmission services.[1] Thus, there is no need to make separate payments in real time to relieve congestion in the day-ahead schedule, as there was in California. The day-ahead schedules under Standard Market Design would also be financially binding so that a marketer that changed its schedule in real time would still be financially liable for its day-ahead schedule. This also reduces the opportunities and incentives for market manipulation strategies that rely on differences between day-ahead and real-time prices.

A few of the strategies in the Enron memoranda appear to depend on the marketer providing false information to the ISO. Thus, these strategies rely on evading or violating the market rules rather than on market design flaws. Standard Market Design addresses these types of strategies by requiring an active market monitoring program that will detect violations of market rules and take appropriate action against entities that violate the market rules.

The specific strategies in the Enron memoranda are discussed below.

A. The Big Picture

1. "Inc-ing Load" (Fat Boy)—artificially increasing load on schedules submitted to the Cal PX; dispatching the generation as scheduled, which was in excess of actual load; being paid by the California ISO for the excess generation at the market clearing price.

This strategy appears to be designed to evade the requirement for balanced day-ahead schedules by the California ISO. Standard Market Design does not require load or generation to submit balanced day-ahead schedules. Therefore, such a strategy is not necessary to offer excess generation to the market. The market rules provide sellers with varying methods to do this. However, there are scheduling requirements and entities that do not follow them may be subject to penalties.

2. *Relieving Congestion*—creating congestion in the PX market (*i.e.,* the energy scheduled for delivery exceeds the capacity of the transmission path) and "relieving" such congestion in the real-time market. Accomplished by reducing schedules or scheduling transmission in the opposite direction, for which congestion payment is made by the ISO.

This strategy appears designed to exploit a flaw in the California market design that is not present in Standard Market Design. The day-ahead schedule for energy developed by the PX market did not take into account transmission constraints. As such, the schedule that was developed was often not physically feasible. Second, entities were then paid to relieve the congestion in real-time that resulted from the infeasible day-ahead schedule. In contrast, Standard Market Design uses a security constrained day-ahead schedule for energy. This means the day-ahead schedule accounts for all transmission system constraints needed for reliable system operations. Thus, the day-ahead schedules in the Standard Market Design will not have the type of manufactured congestion discussed in the Enron memoranda. Standard Market Design also uses a more efficient congestion management system, LMP, than that used by the California ISO. Under LMP, the entities that cause congestion are charged for that congestion. Thus, there would be no need for separate payments by the ISO to relieve congestion as occurred in California.

B. Representative Trading Strategies

1. Exports of California Power—buying energy for export and then importing that energy to evade the price caps in California.

The strategy was designed to take advantage of the fact that there was a price cap in effect in only part of the market. This problem was eliminated in California when West-wide mitigation measures were imposed. Standard Market Design will apply consistent market mitigation measures across all regions. Thus, the incentive for this type of strategy is significantly reduced. Also, Standard Market Design includes a resource adequacy requirement for load serving entities that avoids or minimizes the energy shortage conditions that made this strategy possible.

2. Non-firm Export—scheduling non-firm energy from a point in California to a control area outside of California and then cutting the non-firm energy after it receives payment for relieving congestion.

This strategy appears to exploit a loophole in the California congestion management system that allowed an entity to get a payment for shipping power that wasn't actually shipped. In contrast, under Standard Market Design the day-ahead schedule would be financially binding so a marketer could not cancel the arrangement without a financial penalty. Also, Standard Market Design uses LMP to manage congestion rather than separate payments to relieve congestion.

3. Death Star—scheduling energy in the opposite direction of congestion (counterflow) without putting energy onto or taking it off of the grid, yet still receiving congestion payments.

This strategy appears designed to exploit a flaw in the way that congestion charges were paid in California. Under LMP, the entity would only be paid in real time for power

[1] California used a zonal congestion management system that was designed to manage congestion between zones, but not within a zone. A nodal congestion management system is designed to manage congestion between any locations or nodes within the transmission system. In California, the day-ahead schedule for energy sales was developed by the PX and there was no requirement that this schedule be physically feasible

that actually flowed. Congestion charges would be computed as the difference between two locational energy prices under a LMP system rather than a separate charge as in California. This particular strategy also appears to depend on different congestion management systems being in effect in contiguous areas. That is, the California ISO's congestion charges did not reflect the availability of additional transmission capacity along a parallel path in an adjacent system. As long as that happens there likely are some opportunities for market manipulation. The long-term fix for this type of problem is a standard market design that applies to all areas within the market. Also, large regional organizations that cover natural markets will fix this problem. In Order No. 2000, the Commission encouraged the formation of these types of regional organizations.

4. Load Shift—submitting artificial schedules in order to receive inter-zonal congestion payments. Shifting load to receive congestion payments.

The strategy relies on the flaws in the congestion management system in California. The zonal congestion system used in California provides more opportunities to game congestion than the nodal congestion system under LMP. Because of the separation of the day-ahead market (formerly administered by the PX) and the real-time balancing market (administered by the ISO), there are numerous ways that market participants can create artificial congestion in the day-ahead market and then be paid to relieve the congestion in real time. Under LMP, the entity that caused the congestion would pay for the congestion.

5. "Get Shorty"—paper trading of ancillary services. Enron has to submit false information to the CA ISO on the location of the plants to sell the ancillary services.

Standard Market Design proposes a day-ahead and real-time market for ancillary services. Financial bids for ancillary services are not permitted. Bidders would be required to identify specific units that would be used to provide the ancillary services. Market monitoring would be used to ensure that ancillary service bids are backed by real resources.

This strategy is also based on virtual bidding, something that is allowed under Standard Market Design for energy markets. Virtual bidding should cause the prices in the day-ahead and real-time markets to converge. This by itself does not harm customers. It means that a customer that buys power in real time will pay approximately the same as a customer that buys power day ahead. However, under Standard Market Design, bidders would be required to specifically identify energy bids that are not backed by physical resources. This is important for reliability purposes, to ensure that the transmission provider can ensure that sufficient physical resources are committed to meet the projected load. In contrast, Enron apparently indicated the ancillary bids were backed by physical resources when they were not. This could have affected reliability if Enron was actually called on to supply the ancillary services.

6. Wheel Out—scheduling a transmission flow while knowing that an intertie is completely constrained or that a line is out of service. Even though no energy is delivered, the trader will be paid a congestion charge for cutting the transaction.

This strategy appears designed to exploit two flaws in the California system that do not exist in Standard Market Design. First, because Standard Market Design uses security-constrained unit commitment and dispatch procedures in operating their energy markets, market participants could not schedule transactions day-ahead or real-time that are physically impossible. Second, the congestion management system under Standard Market Design is fully integrated with the energy markets and therefore would not provide separate payments for relieving congestion as in California. Under LMP, if more entities were trying to schedule an export than the physical capacity of the line, this excess would be reflected in the market clearing prices for the energy exports, which in turn would be used to compute appropriate congestion charges. Thus, there would be nothing to gain in using this strategy.

7. Ricochet—Buying energy from the Cal PX and exporting it to another entity which charges a small fee. The energy is resold in the real-time market.

The main purpose of this strategy is to evade California's price caps which apply to in-state generation, but not to external generation purchased "out of market." Under Standard Market Design there would be consistent market mitigation measures across the country. Therefore, there would not be the opportunity to take advantage of the differences in market rules. In California, the "Ricochet" strategy ended when consistent West-wide mitigation rules went into effect.

8. Selling non-firm as firm—selling or reselling what is actually non-firm energy to the Cal PX but claiming that it is firm energy.

The reason for this strategy is that Enron would get paid for ancillary services if the energy was labeled as firm, but would not get paid for ancillary services if it was labeled as non-firm. Under Standard Market Design all transmission service would be under Network Access Service so there would be no difference in the ancillary service requirements. Thus, there would be no reason for this strategy.

9. Scheduling energy to collect congestion charge—scheduling a counterflow even though a company does not have any available generation. The entity is charged the real-time price for energy that it is short but receives a congestion payment for the scheduled counterflow. This activity is profitable whenever the congestion payment is greater than the charge associated with the energy that was not delivered.

This strategy exploited a loophole in the CA ISO congestion management system that does not exist under the LMP system used in Standard Market Design. As the memorandum notes, CA ISO paid congestion charges whether any power flowed or not. Under Standard Market Design if an entity sold energy in the day-ahead market it would either have to provide the energy in real time or buy back its position (it would be charged the real-time price for the energy). Also, the strategy may be related to the fact that the day-ahead schedule for energy developed by the Cal PX did not account for transmission constraints. CA ISO then paid congestion charges to entities to relieve the congestion they had created through their scheduling. The security constrained day-ahead schedules required in Standard Market Design takes into account transmission constraints. So, there is not the same opportunity for this type of market manipulation.

Market Manipulation in the Eastern ISO Markets: Implications for Standard Market Design

Because several components of Standard Market Design are based on market designs in effect in the Eastern ISOs markets—PJM, New York and New England—it is important to turn to these markets to verify that the Standard Market Design rules protect against market manipulation. In this regard, the following points are important. First, the Eastern ISO markets have recognized almost from the start of market operations that no market design can protect against market power due to structural conditions, such as the high concentration of firms in a region or load pocket and/or the lack of price-sensitive demand. For this reason, the Standard Market Design includes market power mitigation rules.

Second, there have been several years of learning in the Eastern ISO markets on market design. Small details of market design can turn out to have major effects on market performance. We have used this experience in developing the market rules for Standard Market Design.

Like the California markets, the Eastern ISO markets have been alleged to be subject periodically to physical and economic withholding of capacity by firms and other measures employed as a means to increase market prices for energy, ancillary services and installed capacity, and to manipulate the prices for transmission rights. However, these attempts have been more sporadic and have had a far less significant economic impact than California. This is due in part to the fact that approximately 85 percent of demand is covered under long-term contracts and therefore is unaffected by spot price volatility. In general, the Eastern markets are considered relatively competitive and have a range of measures in place to monitor and mitigate locational market power.[2] Several problematic markets, especially for installed capacity, have been eliminated or substantially modified. In addition, at least some types of market manipulation that have occurred in the New England market are associated with its interim market design,

[2] Each of the Eastern ISOs produces reports on market performance and on market power monitoring and mitigation. These reports are available on the ISO Web-sites; particular reports referenced in this section will be cited. In addition, filings before the Commission and Commission orders address these issues and will also be cited when referenced. *See also* FERC, "Investigation of Bulk Power Markets: Northeast Region," November 1, 2000, available on the FERC web-site; State of New York Department of Public Service, "Interim Pricing Report On New York State's Independent System Operator," Department of Public Service Pricing Team, December 2000.

and will not recur under the Standard Market Design. Similarly, in New York, many initial poor design decisions and software choices made within a framework similar to the proposed Standard Market Design have been modified and improved, yielding some lessons for future attempts to implement Standard Market Design markets.[3]

The previous section examined whether the Enron strategies in California could be used to manipulate prices under the Standard Market Design. This section reviews some of the publicly known examples of market manipulation in the Eastern ISO markets and discusses whether and how the Standard Market Design would prevent such activity.[4] The ISO market monitoring reports and filings before the Commission provide many further examples of market manipulation in the Eastern ISO markets that concern either minor events, transitory problems, or market rule changes made in anticipation of potential market manipulation. The Standard Market Design may not specifically require many of those rules, but the Commission will review Standard Market Design compliance filings to evaluate whether proposed market rules are susceptible to manipulation.

A. Energy Markets

The Eastern ISO energy markets have been subject to forms of market manipulation and market power, including both economic and physical withholding. Most exercise of market power in the energy markets occurs in two types of system conditions: (1) The existence of persistent transmission constraints in some locations and (2) periods of system-wide shortage of energy, such as exists on peak-load days or during emergencies. Locations that are on the import side of persistently congested transmission lines (sometimes called ''load pockets'') present the most opportunity for exercise of market power due to the high concentration that occurs in these locations. Generators in these locations are typically closely monitored and/or placed under contract to prevent bid price increases. Hence, this section will not consider market power in these locations.

During capacity shortages or system emergencies, market power is more diffuse, reflecting the possibility that all generation will have to be dispatched. For example, the PJM market monitor believes that high energy prices in the summer of 1999 were the result of the interaction of high demand levels with supply curves that exhibited steep slopes over very narrow ranges of output. Some firms appear to have withheld capacity and changed bid parameters during peak hours as a means to drive up prices (*see* discussion below). However, these prices also appear to have attracted imports into PJM. The market monitor thus concluded that the high prices were due both to scarcity and to the exercise of market power, but that the relative importance of the two factors could not be determined.[5]

During periods of shortage, interactions between the energy markets and the markets for ancillary services and installed capacity are also more significant. Market power in each type of market can affect the other. Price increases in the energy markets will lead to higher prices for ancillary services, since the prices in the latter markets reflect the opportunity costs associated with forgone energy sales.[6] Maintenance of the operating reserve requirement can also drive up prices in the energy market, because the ISO markets require that all energy should be taken to preserve the reserve margins prior to having to reduce them (see example 1(a), below); hence withholding of reserves could drive up not just reserve prices but also energy prices.[7]

1. Manipulation of physical bid parameters to extend the operating time or increase the output level of a generator and increase the market price—Several ISO markets have experienced firms' use of the bid-in physical parameters of generators, such as minimum run times and low operating levels, to extend the operating time and/or output of the generator and possibly set a higher market clearing price than was economically necessary. Typically, these problems are combined with specific market rules that allow the change in physical bid parameters to impact the price (under a purely competitive market assumption, changes in these parameters should not affect the price in the market). Two specific cases follow.

(a) In PJM, certain generators were increasing their minimum run times to the full 24 hours of the day and submitting high price bids. Under the PJM energy market rules, the bids were evaluated over the full day; hence, under normal conditions, high price bids would be rejected. However, in Maximum Generation Emergencies, PJM was required to take all economic offers, regardless of the number of hours of the day in which such offers were economic, prior to taking other emergency measures, such as recalling capacity resources. This allowed these generators to run at a high price all day and set LMPs higher than the $1,000 bid cap. PJM estimated that in 1999, excess energy payments to just one plant of $8 million resulted from this bidding technique. The Commission approved PJM's market rule revision to address this problem, which restricted the bid sufficiency guarantee only to the hours in which the generator bid was economic during the emergency.[8]

Under the proposed Standard Market Design market rules, as in PJM, a generator's bid offer must be considered over the full day. Hence in normal circumstances, as in PJM, changing the generator's minimum run time should not confer any competitive advantage. The Standard Market Design rules explicitly require that the Transmission Provider must evaluate how emergency conditions affect market prices. In complying with this requirement, the Commission will evaluate whether the rules prevent market manipulation, whether by adopting the PJM rules or some other measures.

(b) In New England, generators were bidding very high low operating levels—that is, setting a high minimum output level. By the existing rules in New England, these generators were not eligible to set the Energy Clearing Price but were eligible for uplift payments based on their bid. The ISO proposed, and the Commission accepted, that generators would be required to bid their physical low operating levels, subject to adjustment for emissions or economic efficiency reasons.[9] This kind of problem would be less likely in an LMP-based system with a revenue sufficiency guarantee.

Under Standard Market Design, the Transmission Provider is given authority to put limits on the frequency with which physical bid parameters can be changed, and other limits on how the operating characteristics of the generators are bid. These potential bid restrictions can be used to address any evidence of market manipulation or to anticipate such behavior.

B. Ancillary Service Markets

Bid-based ancillary service markets typically have fewer eligible suppliers (particularly until demand-side resources participate) than the energy markets as well as inelastic demand (unless demand curves for reserves are established). Locational reserve requirements may narrow the markets further. Finally, as noted above, market power in the energy markets is transferred to the ancillary service markets through opportunity cost payments and other market rules.[10] These factors make monitoring of these markets important. Under normal conditions, it is expected that regulation and operating reserves should account for under 10 percent of total market costs, and in the Eastern ISO markets are often under 5 percent. In contrast, in a few cases, poorly designed ancillary service markets and/or exercise of market power in these markets have resulted in ancillary services

[3] David B. Patton and Michael T. Wander, ''2001 Annual Report on The New York Electric Markets,'' Independent Market Advisor to the New York ISO, June 2002.

[4] Some paragraphs in this section are excerpted from FERC, ''Investigation of Bulk Power Markets: Northeast Region,'' November 1, 2000.

[5] PJM Market Monitoring Unit (MMU), ''PJM Interconnection State of the Market Report 1999,'' June 2000. The report explains that long-term net revenue results indicate that prices were competitive in 1999.

[6] The standard pricing rule for regulation and operating reserves is to compensate generators that would have been scheduled for energy but are withheld for regulation or reserves for the forgone energy revenues. This pricing rule is continued in the Standard Market Design.

[7] In addition to the example in 1(a), there are some significant instances in which the reliability rules that require ISOs to purchase energy from any external or internal source to maintain the reserve margin can increase the energy price. For example, prior to the imposition of the $1000 energy bid cap in the Eastern ISOs, ISO New England experienced an $6000/MWh energy clearing price for four hours in May 2000 due to an import purchase that was taken to avoid degrading the internal reserve margin. However, this case was not deemed to be exercise of market power. *See* FERC, ''Investigation of Bulk Power Markets: Northeast Region,'' November 1, 2000.

[8] *See* PJM Interconnection, L.L.C., 92 FERC ¶ 61,013 (2000).

[9] *See* ISO New England, Inc., 99 FERC ¶ 61,124 (2002).

[10] PJM Market Monitoring Unit (MMU), ''PJM Interconnection State of the Market Report 2001,'' PJM Interconnection, L.L.C., June 2002, p. 108.

temporarily accounting for a much higher percentage of total electricity costs.[11]

1. Withholding of Operating Reserves—The New York ISO markets for operating reserves experienced withholding of operating reserves in the Spring of 2000, resulting in substantially higher prices for these products for several months.[12] In particular, ten-minute non-spinning reserves were both withheld from the market physically or bid in at a high level by the three major suppliers. The high price for this reserve in turn drove up prices for regulation and the other operating reserves. In response, the Commission approved a bid cap on ten-minute non-spinning reserves and the New York ISO took additional measures to increase supply.[13] The Commission subsequently imposed a bid cap on non-spinning reserves in the ISO New England markets for similar reasons.[14] PJM delayed the start of a ten-minute spinning reserve market in part due to concerns about the potential for limited sellers of the product.

As in the energy markets, Standard Market Design auctions alone cannot solve structural sources of market power in the regulation and operating reserves markets. Rather, these problems must be addressed through a combination of market power mitigation measures, such as bid caps, and structural solutions, such as encouraging entry into these markets by generators with flexible start-times.

C. Congestion Management Systems and Transmission Rights

The congestion management system based on LMP and financial transmission rights proposed in the Standard Market Design and in use in PJM and New York presents a clear advantage over the transmission line-loading relief (TLR) methods used in other parts of the country. The LMP-based method has caused far fewer instances of transmission curtailments.[15] At the same time, any transmission network with congestion pricing and financial transmission rights is susceptible to some degree to market manipulation.[16] Heretofore, there has been some evidence of manipulation of these design elements in the Eastern ISO markets, although nothing that has disrupted the markets. Nevertheless, under Standard Market Design, such behavior will be monitored for and mitigated if found.

Care must be taken to discriminate between legitimate transactions and those aiming to favor owners of certain generation or transmission assets. Increasing congestion is not necessarily a sign of intentional activity to congest; all the Eastern ISOs report increasing congestion as market trading increases simply because there is more demand for distant resources and associated transmission. In addition, changes in congestion accounting may increase the amount of apparent congestion[17] and transmission maintenance or outages can also have a major effect.

An important financial linkage in the Standard Market Design is between the congestion management system and the holding of Congestion Revenue Rights. The Standard Market Design rules aim to find a method of allocation, trade and settlement of such rights that is equitable, transparent, provides appropriate incentives for maintenance of and investment in transmission assets, and is resistant to manipulation. The following example shows how market manipulation can occur.

1. Sharing of information about Transmission Maintenance by Transmission Owners to affect the value of affiliates holdings of Transmission Rights—In PJM, information acquired during a non-public investigation suggested that subsidiaries of Exelon, may have shared information that gave the marketing subsidiary an informational advantage in its bidding for Fixed Transmission Rights (FTRs) in the monthly FTR auctions. After the bidding closed in three auctions held in September, October, and November 1999, PECO announced maintenance outages on transmission facilities within PJM. The Commission directed Exelon, PECO and Exelon Power Team to show cause whether they violated section 205(b) of the Federal Power Act (FPA) and the standards of conduct and the Commission's regulations by operating PECO's transmission system in an unduly preferential manner or sharing non-public information regarding the timing and location of maintenance outages in PJM's system or both. The Commission also directed PJM to report, to the Commission on its current transmission oversight processes and procedures regarding maintenance and de-rating decisions.[18] PJM subsequently modified its transmission oversight procedures to eliminate incentives for such behavior.[19]

This problem is generic to electricity markets with transmission rights. The rights established under Standard Market Design, which include financial rights analogous to FTRs in PJM, are susceptible under some conditions to manipulation by transmission owners and their affiliates. The Standard Market Design requires market monitoring and appropriate transmission maintenance oversight and incentives to mitigate such problems.

D. Installed Capacity Markets

Each of the Eastern ISO markets has an installed capacity requirement and an ISO-operated capacity market (with the exception of New England, in which the market was terminated). The design of these markets is different in each ISO, as is the market structure (that is, the degree of firm concentration in the market); hence, the problems experienced in each market have also been different. As discussed in this proposed rule preamble (Section H), for various reasons the proposed Standard Market Design includes a resource adequacy requirement similar in purpose to what is called here ''installed capacity'' but does not include either specific rules for a tradable capacity product or a centralized market to provide such adequacy. However, regions may choose to establish such markets. This section discusses some of the market manipulation that has been experienced in the existing ICAP markets. The Commission will evaluate any proposals for new markets for resource adequacy on the basis that they do not result in a repeat of the flaws detected in the existing ISO installed capacity markets.

1. Bid Manipulation of poorly defined ICAP products (New England)—The original ISO New England ICAP market was recognized as a flawed market almost from its inception (along with other aspects of the New England markets),[20] but the true problems and attempts at market manipulation did not emerge until several months into operations. The basic flaw was that the ICAP product did not have any recall obligations or deliverability requirements and had only seasonal availability requirements. Hence, its value in the monthly auction was determined not by the value of ICAP but by the ability to manipulate the price. The auction clearing price tended to swing between $0/MW and very high prices. In early 2000, the ISO determined that the ICAP price was due to

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[11] For example, New York ISO experienced one month, February 2000, in which regulation and operating reserves accounted for almost 30 percent of total market costs. This was an aberration due to the market power in the reserves markets discussed in example (1); following market power mitigation measures, the costs of these ancillary services dropped to under 5 percent of total market costs. *See* Patton, David B., ''New York Market Advisor Annual Report on The New York Electric Markets for Calendar Year 2000,'' ISO New York, April 2001, p. ix.

[12] *See id.*

[13] New York Independent System Operator, Inc., *et al.,* 91 FERC ¶ 61,218 (2000).

[14] *See* ISO New England, Inc., 99 FERC ¶ 61,124 (2002).

[15] *See, e.g.,* FERC, ''Investigation of Bulk Power Markets: Southeast Region,'' November 1, 2000; and FERC, ''Investigation of Bulk Power Markets: Midwest Region,'' November 1, 2000.

[16] Although electricity flows in complex patterns determined by physical laws and subject to the simultaneous interaction of all injections and withdrawals on the systems, the ways in which generators load certain lines can be calculated (through so-called ''generation shift factors'') or understood through experience.

[17] For example, PJM reports a notable increase in congestion over low-voltage facilities, which is at least in part associated with PJM assuming monitoring and control of these facilities from transmission owners. *See* PJM Market Monitoring Unit (MMU), ''PJM Interconnection State of the Market Report 2001,'' PJM Interconnection, L.L.C., June 2002, p. 126.

[18] *See* PJM Interconnection, L.L.C., 97 FERC ¶ 61,010 (2001).

[19] *See* PJM Interconnection, L.L.C. ''Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures, Docket No. EL01–122–000 (November 2, 2001).

[20] The preliminary New England market design was developed by NEPOOL committees over the course of 1998. Problems with this design were suggested by independent experts under contract to the ISO (*See* Peter Cramton and Robert Wilson, ''A Review of ISO New England's Proposed Market Rules,'' Report to ISO New England, Market Design Inc., September 1998). However, these experts, the ISO and NEPOOL supported beginning market operations and addressing market design problems with the markets in progress. NEPOOL proposed a phased implementation which was approved by the Commission. Market trials were run in January 1999 and the markets were started on May 1, 1999.

market power and revised the price for several months.

The subsequent modifications of the New England ICAP requirements and markets will not be reviewed here. In a June 28, 2000, order, the Commission agreed with the ISO that the existing installed capability auction market was not useful and that it could produce inflated prices unrelated to the actual harm created by installed capability deficiencies.[21] The Commission permitted the elimination of the auction market effective August 1, 2000, and required the ISO to revert to administratively-determined deficiency charge for failure to meet installed capability requirements.

2. Withholding of ICAP (PJM)—In the ICAP markets in PJM and New York, both structural problems and market design issues have resulted in ongoing refinement of market design and measures to limit the exercise of market power. An in-depth explanation of the designs of these markets is beyond the scope of this section; rather, the focus will be on the exercise of market power in the PJM daily capacity credit market in early 2001. The PJM market monitor has noted potentially high concentration and design flaws in this market since its inception on January 1, 1999, and there have been modifications of the market rules several times.

In PJM, each load-serving entity has the obligation to own capacity, have a bilateral contract for capacity, or purchase capacity credits through a centralized market equal to its peak load plus a reserve margin. To qualify as a capacity resource, a generating unit must pass tests regarding overall capability and the ability to deliver energy to PJM load, which requires adequate transmission capability. Load-serving entities can use their capacity resources to produce energy for export from the PJM control area, but such transactions are subject to recall by PJM in emergencies. If a load-serving entity's capacity resources are less than its obligation, then it is considered deficient and subject to a penalty. In 2001, the capacity credit market was operated on a daily, monthly and multi-monthly basis as well as on an ''interval'' basis defined by seasons (the daily market serves residual demand after the markets for longer-term credits close).

Between January and April 2001, a single firm raised the price in the daily capacity credit market for a sustained period of time by essentially being in a position that required all buyers that were short of capacity to have to purchase some or all of their capacity from it. The determination that this price increase was the exercise of market power through economic withholding was made on the basis of the excess capacity available at the time as well as calculation of the opportunity cost of that capacity, which is the sale of the firm energy output forward into a neighboring market. Effective June 2001, the Commission approved market rule changes that diminished the incentive to economically withhold by spreading the revenues accruing to owners of excess capacity to all compliant load-serving entities rather than to the single firm.[22]

Appendix F

Access Charges and Congestion Revenue Rights

Allocation of Congestion Revenue Rights

Phase I (Initial Allocation)—Through Direct Assignment Based on Historical Use

All existing customers using transmission service, whether through bundled contracts, service agreements under the *pro forma* tariff, or pre-Order No. 888 transmission contracts, pay the transmission rate, *i.e.*, the access charge, which enables the transmission owner to recover the fixed, or embedded, costs of its transmission system. Moreover, the existing *pro forma* tariff grants priority for transmission capacity to existing long-term firm customers.

This proposed rule gives the region a choice between an initial allocation or an auction of Congestion Revenue Rights. The first portion, ''Phase I,'' deals with regions that start with an allocation of Congestion Revenue Rights to existing long-term customers based on their historical use of the system. In this sense there is a link between paying the access charge and receiving Congestion Revenue Rights. However, this is not a one-to-one link, *i.e.*, not all customers paying the access charge will receive Congestion Revenue Rights—customers with short-term or non-firm service under the existing *pro forma* tariff currently pay an access charge but would receive no Congestion Revenue Rights through the initial allocation process. This is consistent with Section 2.2 of the existing *pro forma* tariff, which grants rollover rights (which guarantee access to firm service) only to longer-term contracts.

Phase I: Specific Examples—What the Customer Pays and What the Customer Gets

The following answers the question of whether and how the following customers currently receiving various services will pay access charges or receive Congestion Revenue Rights. All service in the following examples would be performed under Network Access Service upon implementation of Standard Market Design.

A. Short-Term and Non-Firm Contracts (less than one year in duration)

These customers would receive no Congestion Revenue Rights (however, transactions under which power is taken off the grid pay an access charge; those under which power is not taken off the grid do not pay an access charge). These contracts would be converted to Network Access Service at the time Standard Market Design is implemented through the SMD Tariff.

B. Long-Term Contracts (one year or longer)

1. Existing Network Integration Transmission Service—These customers currently pay and would continue to pay the access charge, and would receive a direct allocation of Congestion Revenue Rights.

2. Existing Point-to-Point Service.

a. Load-Serving Entity (service to load within a single Transmission Provider's area)—These customers currently pay and would continue to pay the access charge, and would receive a direct allocation of Congestion Revenue Rights.

b. Internal, Non-Load Serving Transactions (service within a single Transmission Provider's area from generator to hub, hub-to-hub, or to support sales to the spot market)—The customer currently has specific rights to capacity between stated points and, for this, pays the access charge. Under Standard Market Design, it would be permitted to retain its priority rights, albeit in the form of Congestion Revenue Rights rather than firm transmission capacity rights through Phase I. For this continued right, however, the customer must continue to pay the access charge to receive a direct allocation of Congestion Revenue Rights. In other words, it could choose to either (1) continue the point-to-point contract, including paying the access charge, and for that would receive a direct allocation of Congestion Revenue Rights; or (2) terminate the contract, meaning the customer would no longer pay the access charge, no longer receive specific transmission capacity rights between points, and, therefore, would not receive a direct allocation of Congestion Revenue Rights. Under the second choice, the customer would instead schedule service in the day-ahead and real-time markets and pay the applicable congestion and loss charges.

c. Through and Out (export by generator or marketer)—Consistent with internal, load-serving transactions (above), the customer currently has specific rights to capacity between stated points and, for this, pays the access charge, but would no longer be required to pay the access charge to export power to another region. It would be permitted to retain its priority rights, albeit in the form of Congestion Revenue Rights rather than firm transmission capacity rights through Phase I so long as it continued to pay an access charge on the source Transmission Provider's system. In addition, the access (or scheduling) charge paid by all load-serving entities taking power off of the grid on the sink side of a transaction involving two Transmission Providers' systems would include a portion of the transmission costs from the source side of the transaction, as explained below.

3. Existing Pre-888 Transmission Contract—These contracts are not standard and may have characteristics of Network Integration Transmission Service or Point-to-Point Transmission Service. Customers currently pay an access charge (though likely a different charge than under the *pro forma* tariff). In either case, the load-serving entity (the transmission owning public utility who currently is the transmission provider), would pay the Transmission Provider the access charge on behalf of the pre-888 customer, and would receive any direct allocation of the Congestion Revenue Rights associated with the contracts, unless the customer converted its contract to Network Access Service. Continued payment of the access charge and direct allocation of Congestion Revenue Rights would be based

[21] *See* ISO New England, Inc., *et al.,* 91 FERC ¶ 61,311 (2000).

[22] *See* PJM Interconnection, L.L.C., 95 FERC ¶ 61,175 (2001).

on the nature of the service and would be determined consistent with the pattern established above.

4. Bundled Wholesale Contract—Like pre-888 transmission contracts, these contracts are not standard and may have characteristics of Network Integration Transmission Service or Point-to-Point Transmission Service. Customers currently pay an access charge (though likely a different charge than under the *pro forma* tariff). Like the pre-888 contracts, the load-serving entity (the transmission owning public utility who currently is the transmission provider), would pay the Transmission Provider the access charge on behalf of the bundled wholesale customer, and would receive any direct allocation of the Congestion Revenue Rights associated with the contracts, unless the customer converted its contract to Network Access Service. Continued payment of the access charge and direct allocation of Congestion Revenue Rights would be based on the nature of the service and would be determined consistent with the pattern established above.

5. Bundled Retail Customers—There is no specific contract defining transmission rights for this type of service. Customers currently pay an access charge through the bundled rate. The load-serving entity, often the transmission owning public utility who currently is the transmission provider, would pay the Transmission Provider the access charge on behalf of the bundled retail customer, and would receive a direct allocation of the Congestion Revenue Rights.

6. Retail Choice—Customers in states with retail choice are either transmission customers under the *pro forma* tariff, or they are buying power from a supplier who is acting as the transmission customer on their behalf. They currently directly (or indirectly through the supplier) pay the access charge. The transmission customer in these transactions would receive the direct allocation of Congestion Revenue Rights. However, if the retail customer switched suppliers, this proposed rule establishes the principle that the Congestion Revenue Rights move with the load (*i.e.*, the Transmission Provider would have to periodically reallocate the Congestion Revenue Rights based on each load-serving entities' load ratio share).

Phase II (within four years of adoption of Standard Market Design)—Through an Auction

Under Phase II, Congestion Revenue Rights (other than those assigned to an entity on a ''life of the facility'' basis as a result of the customer paying for the network upgrades) will be auctioned off rather than allocated to particular customers. The link between paying the access charge and receiving Congestion Revenue Rights will no longer exist once we move to a full auction, since any entity can acquire Congestion Revenue Rights through the auction, with no requirement to pay an access charge to get them. Instead, the link moves to the revenue side, *i.e.*, the auction revenues would be returned to those customers paying the embedded costs of the system through an access charge.

Are There Differences in the Allocation of Congestion Revenue Rights Based on How the Rates Are Paid?

1. Service with rate based on open access tariff's embedded cost charge.

a. At the time of direct allocation—this is defined above (long-term customers pay the access charge and get the direct allocation of Congestion Revenue Rights)

b. At the time of the auction—this is defined above for various categories of customers (some customers will continue to pay the access charge, which will be reduced by auction revenues, but all Congestion Revenue Rights will be auctioned)

2. Service with rate based on incremental cost of new transmission facilities.

a. At the time of direct allocation—When a customer requests firm service under the existing *pro forma* tariff and network upgrades must, on occasion, be built to accommodate the service. The Commission has historically allowed rates for transmission service to be set at the higher of the incremental cost or the average embedded cost. Thus, the allocation of Congestion Revenue Rights for customers who are currently paying an incremental rate for transmission service will, therefore, be the same as for customers paying the embedded cost charge under the *pro forma* tariff for transmission service.

b. At the time of the auction—Under Standard Market Design, customers generally will no longer request to build facilities to receive ''firm'' service, since all service will be allocated based on the customer's willingness to pay congestion costs. Rather, customers will request an economic expansion in order to avoid paying the cost of congestion. For economic expansions that are not rolled in to the embedded cost charge, the customer will pay the Transmission Provider the cost of the new facilities in order to acquire the Congestion Revenue Rights, and will continue to pay the access charge to receive Network Access Service.

3. Economic Expansions—once an Independent Transmission Provider is in place, it (with state participation) would make a decision on pricing. Most likely, the beneficiary(ies) of the economic expansion of the network would pay for the cost of the new facilities in return for any Congestion Revenue Rights created by an increase in transfer capability, and will continue to pay the access charge to receive Network Access Service. Otherwise, all network expansions would be rolled in either regionally or to a license plate zone and, therefore, all newly created Congestion Revenue Rights would be auctioned.

4. Reliability Expansions.

a. At the time of direct allocation—reliability expansions benefit all users of the grid; therefore, the costs are rolled-in to the access charge either regionally or to a license plate zone. Accordingly, any newly created Congestion Revenue Rights associated with the expansion will be auctioned.

b. At the time of the auction—the introduction of the full auction would have no impact on reliability expansions, which will continue to be rolled-in either regionally or to a license plate zone with any newly created Congestion Revenue Rights associated with the expansion offered in an auction.

5. Generator that receives credits for network upgrades.

a. At the time of direct allocation—currently, the interconnecting generator pre-pays for transmission service and receives credits against the monthly cost of transmission service, whether the generator is the customer or it is chosen as a network resource by a load-serving entity. To the extent the generator is a long-term transmission customer, it would receive Congestion Revenue Rights associated with its transmission service (otherwise the network customer that chose the generator as a network resource would receive the Congestion Revenue Rights).[1] If participant funding is adopted, the customer would receive the Congestion Revenue Rights associated with the additional transfer capability made possible by the transmission expansion. This pricing is subject to the outcome of the Generator Interconnection proposed rule in Docket No. RM02–1–000.

b. At the time of the auction—a generator would be treated in the same fashion as other customers under the *pro forma* tariff both with respect to payment of the access charge and receipt of Congestion Revenue Rights. If participant funding is adopted, the customer would receive the Congestion Revenue Rights associated with the additional transfer capability made possible by the transmission expansion. This pricing is subject to the outcome of the Generator Interconnection proposed rule in [Docket No. RM02–1–000.

6. Merchant transmission owner.

a. At the time of direct allocation—A merchant transmission owner does not receive service, but rather is a transmission owner. A customer using this facility would also have to pay for service across the RTO plus a rate for service on the merchant facility. Accordingly, the merchant transmission owner would pay for the full cost of constructing the new facilities and would receive the Congestion Revenue Rights associated with its facility for the economic life of the facility. The full amount of those rights may be subject to change based on changes in the overall grid over time (*e.g.*, changes in flow patterns or deterioration of transfer capability of other lines may diminish the amount of Congestion Revenue Rights associated with the merchant facility).

b. At the time of the auction—the introduction of the full auction will not change the way merchant facilities are addressed—the merchant transmission owner would pay for the full cost of constructing the new facilities and would receive the Congestion Revenue Rights associated with its facility for the economic life of the facility.

[1] There could be situations where the transition to Network Access Service occurs prior to a customer receiving transmission credits it is entitled to. To the extent that such a customer would no longer be required to pay the access charge, we would expect the RTO or Independent Transmission Provider to return the remaining amounts to the customer at the same rate as if the current transmission charge were still in place until the balance is returned.

Cost Shifts Due to Eliminating the Access Charge for Inter-Regional Transfers

This rulemaking proposes to eliminate transaction fees (the access charge) on through and out transactions. This, by definition, raises the possibility of cost shifts, resulting in winners and losers. This scenario has been previously faced and resolved within a Transmission Provider's service area, with the result being the elimination of pancaked rates, and can be resolved across multiple service areas as well.

Currently, all transmission customers pay a share of the embedded costs of the transmission system. Under Standard Market Design, only load-serving entities (*i.e.*, customers taking load off of the grid) will pay a share of the embedded costs of the system through an access charge.[2] This means that the portion of embedded costs currently paid by customers transmitting power through or out of a Transmission Provider's service area must be picked up by load-serving entities. However, while this may seem like a rate increase, the benefits from the elimination of the interregional access charge should exceed the costs. Specifically, this occurs through the reduction in generation costs across the region, as we will explain below.

Current situation on a hypothetical RTO (or transmission provider's system): 90 percent of the embedded costs are paid for by bundled retail customers, network customers, and point-to-point customers who serve load within the RTO. 10 percent of the embedded costs are paid for by point-to-point customers exporting power to another RTO or moving power within the RTO but not to load.

Standard Market Design will have two transmission rate impacts: First, the non-load serving transactions will no longer pay the access charge. Second, the inter-regional transfers will be netted across RTOs and the load-serving entities on the net importing RTO will pay a load ratio share of the embedded costs of the exporting RTO. On first blush, it would appear that the load-serving entities on both RTOs will pay more of the embedded costs to make up for the fact that exporting generators will no longer pay an access charge. While this is true with respect to transmission costs, it ignores the intended benefit of this rate change—lower generation costs.

First, access charges paid by generators for the first leg of a transaction, whether to serve load in the same or a neighboring RTO, are ultimately paid by the purchaser of the power. So, recovering these costs directly from the load-serving entities will not increase the overall cost of delivered power.[3]

More importantly, removing this additional transaction fee reduces the cost of reaching generation on a neighboring RTO. The removal of the transaction cost makes cheaper generation available across a broader area, which leads to a more optimal dispatch and lower generation cost for all customers.

For example, assume load is served at a particular location in RTO A at an LMP of $25, and that there is a generator on neighboring RTO B willing and able to sell at $24 (*i.e.*, it has available capacity and there is no transmission constraint between the sink and source). However, RTO B has an access charge of $2, making the competing generator's delivered cost non-competitive at $26. Removing the $2 transaction fee reduces the generator's delivered cost to $24, saving all customers at that location $1, since the LMP is reduced from $25 to $24. Moreover, to the extent that other load within RTO A is served with generation cost in excess of $25, the $25 generator in RTO A that was displaced by the $24 generator in RTO B is now available to meet this load, providing greater generation savings across RTO A. Given that generation costs far exceed access charges, customers' overall savings (generation plus transmission costs) can be reduced far below the increase in transmission costs resulting from the elimination of the access charge on inter-regional transactions. There could be additional savings to the load-serving entities in that they would receive additional Congestion Revenue Rights (or the associated auction revenues) that would otherwise be held by the point-to-point customers.

The precise details of how current contracts will be transitioned and how embedded transmission costs associated with inter-regional transactions will be netted across regions should be left to regions to work out in compliance filings.

[2] This may also include point-to-point customers who continue to pay the access charge to receive Congestion Revenue Rights.

[3] It is possible that there will be instances where a bundled purchase contract, if not reformed to reflect this change in transmission rate design, will result in the customer paying twice for transmission service. Affected customers could file under section 206 of the FPA to seek reformation of their contracts.

Appendix G

Security Standards for Electric Market Participants

Purpose

Wholesale electric grid operations are highly interdependent, and a failure of one part of the generation, transmission or grid management system can compromise the reliable operation of a major portion of the regional grid. Similarly, the wholesale electric market—as a network of economic transactions and interdependencies—relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch and market software and systems. Because of this mutual vulnerability and interdependence, it is necessary to safeguard the electric grid and market resources and systems by establishing minimum standards for all market participants, to assure that a lack of security for one resource does not compromise security and risk grid and market failure for the market or grid as a whole.

The purpose of these standards is to ensure that electric market participants have a basic Security Program protecting the electric grid and market from the impacts of acts, either accidental or malicious, that aren't authentic or could cause wide-ranging, harmful impacts on grid operations and market resources. A basic Security Program for electric grid and market resources (hereafter referred to as market resources) shall cover governance, planning, prevention, operations, incident response, and business continuity.

Security standards for market resources will primarily focus on electronic systems, which include hardware, software, data, related communications networks, control systems as they impact the grid or market, and personnel (hereafter the word cyber shall refer to all of these aspects). In addition, physical security will be addressed to the extent that it is necessary to assure a secure physical environment for cyber resources.

This initial set of security standards represent a minimum set of measures derived from commonly accepted industry standards and practices, such as the Common Criteria, CTSEC, ITSEC, IPSEC, ISO 17799, NIST Guidelines, and the NERC Security Guidelines. Market participants are encouraged to review their individual situation and tolerance for risk and implement a Security Program that goes beyond these basic security standards herein.

Application

These standards are intended to ensure that appropriate mitigating plans and actions are in place, recognizing the role of the participant in the marketplace and the risks being managed. For the purpose of these security standards, participants are defined as, and the standards shall apply to:

- The market operations of RTO's and ISO's, and their market connections to Control Areas,
- Marketers,
- Transmission Owners,
- Power Producers,
- Load-serving entities and other power purchasers,
- NERC and the Reliability Authorities, and
- Tagging (or other similar dispatching) Organizations.

Further, if a power-generating unit participates directly in the grid (*i.e.*, it is electronically dispatched by control centers), the plant control system shall comply with these security standards. If a power-generating unit participates directly in the electric market (*i.e.*, submits tagging requests), its market systems shall also comply with these security standards.

Compliance

These security standards shall become effective on January 1, 2004. Beginning 2004, on January 1 of each year, every participant shall file with FERC a self-certification signed by an officer of the company indicating compliance with these standards and identifying any areas of non-compliance. Failure to comply with these security standards will result in loss of direct access privileges to the electric market.

Malicious acts directed against the electric market, shall be prosecuted by FERC and law enforcement agencies to the full extent of the law, including the recovery of damages.

Security Standards

Governance

Participant senior management shall designate a management official to be responsible for establishing and managing a basic Security Program for electric market functions and resources.

Security Scope

Participants shall define their security perimeter and identify the boundaries and defenses for physical and cyber security that delineate and protect the critical resources under their control. The security perimeter shall identify all entry and exit points and the requirements for access controls.

A Security Program and policy based on these security standards shall be developed to protect critical electric grid and market functions and resources within the security perimeter and at entry and exit points where personnel, supplies or communications may come and go. Additionally, related procedures shall be created that guide implementation and enforcement of the security standards. Policy and procedures shall be reviewed for appropriateness (due to changes in personnel, technology, equipment configuration, vulnerabilities and threats) as necessary, and at least annually.

Asset Classification and Control

Electric market assets within the security perimeter shall be classified as to their criticality in maintaining and protecting electric market functions. A classification system shall further define appropriate levels of protection for each level of criticality, and access rights that will be granted for each level of criticality. All critical assets within the perimeter (computers, networks, doorways, etc.) shall have a custodian who ensures that those assets are handled in accordance with their assigned classification scheme.

Personnel

Any personnel who are authorized access within the security perimeter, or are authorized access to administer, operate or maintain assets within the security perimeter shall be trained on the Security Program and security standards related to their respective positions. This training shall start upon employment, be repeated annually and at career points where significant responsibilities change. Security awareness training shall be provided to all staff.

To the extent permitted by law, personnel required to administer or operate assets classified as critical (according to the participant's classification system) shall undergo background investigation conducted prior to employment, upon promotion to such positions (if not a new hire), and at periodic intervals (not to exceed five years). The participant shall review the results of the background checks and take appropriate action. Individuals shall be disqualified from administering, operating or accessing critical assets if the individual meets any disqualifying criteria specified by the Federal Bureau of Investigation, Office of Homeland Security, RCMP, or other federal agency.

Access Control

A process such as transaction logs shall be in place to identify individual users of critical systems and their time of access. Procedures for critical electric grid and market resources within the security perimeter shall be developed that establish and monitor controls for:

(1) The assignment of both logical and physical access rights (as defined in the classification system);

(2) The prompt disabling of access rights when positions are terminated or job responsibilities no longer require access; and

(3) The annual re-evaluation of assigned access rights.

Such authorized personnel—including visitors and service vendors—shall only have access (whether logical or physical) to electric market resources within the security perimeter that they are authorized for. Any and all unauthorized personnel allowed temporary access within the security perimeter shall be escorted at all times.

Systems Management

Procedures for critical electric market resources within the security perimeter shall be developed to monitor and protect cyber assets, such as:

- Computers
- Software
- Data, as stored and transmitted
- Servers
- Routers
- Modems
- Communications channels, whether owned or leased

At a minimum, these procedures shall address:

(1) The use of effective password routines that periodically require changing of passwords, including the replacement of default passwords on newly installed equipment;

(2) Authorization and re-validation of computer accounts;

(3) Disabling of unauthorized (invalidated, expired) or unused computer accounts;

(4) Disabling of unused network services and ports;

(5) Secure dial-up modem connections;

(6) Firewall software (for routed Internet access);

(7) Intrusion Detection Systems (for networked routers and firewalls);

(8) Patch management;

(9) Installation and update of anti-virus software checkers.

For critical electric systems, operator logs and Intrusion Detection System logs shall be maintained for the purpose of checking system anomalies and for evidence of suspected unauthorized activity. Appropriate procedures for securing control systems that are critical to the grid or market shall be developed and employed. The procedures shall address:

(1) Remote access including modems and other means;

(2) Security patch management, as appropriate;

(3) Assurance that communication channels are adequate so as not to impact the performance of the control system and its critical functions; and

(4) Assurance that system procedures do not impact the performance of the control system and its critical functions.

Procedures for critical electric resources within the security perimeter shall be established to monitor and control physical features, such as:

- Doors,
- Windows,
- Floor space,
- Environmental systems,
- Backup power systems—whether owned or leased.

At a minimum, these procedures shall address:

(1) Appropriate security barriers and entry controls;

(2) Mechanical and electronic key and badge programs;

(3) Access locking of unattended assets; and,

(4) Protection from environmental threats and hazards (*e.g.*, loss of cooling).

Critical electric facilities shall restrict the distribution of maps, floor plans and equipment layouts pertaining to those facilities, and restrict the use of signage indicating critical facility locations.

Planning

Security requirements for critical electric systems within the security perimeter shall be identified, documented and agreed upon prior to development, procurement, enhancement to, installation of and acceptance testing for cyber resources or related physical features. For critical control systems, this means developing cyber security procedures to augment existing test and/or acceptance procedures.

Development and testing of critical electric market systems shall be conducted in system environments that are not interconnected with operational system environments.

Incident Response

Organizations with critical electric market resources shall have incident response procedures, which define roles, responsibilities and actions to rapidly detect and protect electric resources in the event of harmful or unusual incidents, whether accidental or malicious.

Organizations with critical electric market resources shall report incidents to the Electricity Sector—Information Sharing and Analysis Center (ES–ISAC) and use reporting criteria, thresholds and procedures contained in NERC's Indications, Analysis and Warning (IAW) Program.

Business Continuity

Every participant operating a critical electric resource shall have contingency plans that define roles, responsibilities and actions for protecting the rest of the electric grid and market from the failure of its own critical resources. Those plans should further define the roles, responsibilities and actions needed to quickly recover or reestablish electric grid and market functions, processes and systems, in the event that a critical physical or cyber resource fails or suffers harm or attack. Such plans shall be tested or exercised regularly.

References

The North American Electric Reliability Council (NERC) has established and maintains Security Guidelines for the Electricity Sector. NERC also provides a list of additional sources for security best practices. These references shall be helpful in developing organization-specific security standards and procedures for critical market resources.

BILLING CODE 6717–01–P

Annual Self-Certification of Compliance with FERC Security Standards (Due January 31, 2004, and every January 31st thereafter)

Date: ____________________

Subject: **FERC Filing, Annual Self-Certification re: FERC Security Standards**

From: ____(organization name)

____(organization address)

____(organization address)

____(organization address)

This organization certifies the following items regarding FERC security standards for grid-market systems, as of this date:

Compliant	Non-Compliant	Does Not Apply	
☐	☐	☐	Management assignment of grid-market system security.
☐	☐	☐	Security Perimeter defined and documented.
☐	☐	☐	Security Program and Policy developed and documented.
☐	☐	☐	Policy, standards, and procedures reviewed at least annually.
☐	☐	☐	An Asset Classification system defined and implemented.
☐	☐	☐	Security training requirements for personnel with access to critical assets have been met.
☐	☐	☐	All personnel receive security awareness training at least annually.
☐	☐	☐	Critical asset administrators and operators have had background

			screening within last five years.
☐	☐	☐	Access control procedures for authorized personnel are implemented.
☐	☐	☐	Unauthorized personnel inside security perimeter are escorted at all times.
☐	☐	☐	Cyber procedures for system security have been developed and implementation monitored for compliance.
☐	☐	☐	Physical procedures for system security have been developed and implementation monitored for compliance.
☐	☐	☐	Security requirements for developing and testing critical systems have been documented.
☐	☐	☐	Software development systems are not interconnected with operational systems.
☐	☐	☐	Incident response plans are implemented.
☐	☐	☐	ES-ISAC reporting and alert notification procedures are implemented.
☐	☐	☐	Business continuity plans are established and exercised.

Explanation for Non-Compliant Items:

Name: ____(print)

____(title)

____(signature)

BILLING CODE 6717–01–C

Electricity Market Design and Structure

Breathitt, Commissioner, *concurring:*

I am writing separately on the Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD) to express some of my thoughts on certain of its provisions and design elements. We have been discussing the broad contours of the SMD NOPR with interested parties for months through the staff white paper, the options paper and technical conferences. Many of the NOPR's features have been welcomed and embraced by various entities, associations, company representatives and academics. Just as many participants have cautioned us to make sure that the procedures, protocols and standards that we wish to impose on the industry we regulate are practical in implementation, fair to consumers and respectful of state jurisdiction. They have also asked us to recognize that not all regions of the country are the same or have the same historical ways of providing electricity to retail and wholesale customers.

For example, the way the Northeast has evolved with their power pools is vastly different from how the Southeast and the Southwest has traded bulk power. The northwest has a heavy reliance on hydroelectric generated power. Even with these differences, all the regions have provided reliable and steady service especially in times of extreme weather conditions.

People will be pouring over this NOPR to see if it is practical and if it is doable. During the October SMD/RTO week we were advised to keep it simple. This is anything but simple. It is a comprehensive proposal and it's very complicated. Over time it will result in a sophisticated market. Parties are going to need time to understand its complexities and implement its many features. The Commission is going to need patience and flexibility. We have not assigned a cost to this proposal but we know that each FERC jurisdictional entity is required to hire an independent transmission provider (ITP) if they are not already in an RTO. The ITPs must set up locational marginal pricing (LMP), day-ahead and real time energy markets, as well as ancillary services markets.

In Order 2000 we paired a voluntary rule with very tight compliance deadlines, deadlines that I believe we all knew at the time would be difficult to meet. Today's proposed rule pairs many complicated and mandatory requirements with short implementation time lines. For example, the LMP system paired with energy and ancillary services markets has not been proven outside of the tight power pools in the Northeast. Also, allocation of initial Congestion Revenue Rights will be complicated, if not problematic for some areas of the country. But, I am pleased that today's order recognizes that not all areas of the country will be able to move ahead with all requirements of SMD at lightning speed. The Commission intends to be flexible in some compliance dates and while it is the objective to have SMD in place within two years of the effective date of the Final Rule, the Commission will consider requests to extend that date.

The fundamental goal of SMD requirements in conjunction with the standardized transmission service is to create ''seamless'' wholesale power markets that allow sellers to transact easily across transmission grid boundaries. Once the final rule is in place and implemented my hope is that the squabbling over which entities belong in what RTO will end. We should be able to put our magic markers away for good.

Today's NOPR puts forward a detailed vision of the roles that ITPs, this commission and states will play in planning for expansion of the transmission grid. I am pleased that the governors have requested a significant role in transmission planning through the formation of Multi State Entities (or MSEs). I am also pleased that we propose to give MSEs a role in both overseeing the plans developed by the ITPs and in developing a fair pricing methodology for these expansions. I feel very positive about the bottom up approach that is described in the planning section of this NOPR. This approach allows merchant transmission companies and utilities, as well as generators and demand resources, to bring economic solutions to the table to solve the problems of under-built infrastructure. These projects must be vetted by the ITP to determine their impact on the grid in terms of loop flows and other regional impacts, but the real tests will be the demand for the projects much as we see in gas pipeline certificates.

I do have concerns about the planning protocols that would be enacted by the ITP once it is determined that economic projects cannot fulfill all of the reliability requirements of the grid. My concern is that this ''central planning'' aspect may direct projects that are uneconomic with costs socialized to all users of the grid. It is hard to imagine gold plating of the transmission grid when we are in an era of under-built infrastructure, but I believe that once we get the incentives right for building needed infrastructure there will be no need for the ITP to direct the construction of possibly ''uneconomic'' projects.

Getting the incentives right in grid expansion has been on my top ten list through this NOPR process and in my tenure here at the Commission. To this end, I have continued to be a proponent of Independent Transmission Companies (ITCs) and continue to believe that ITCs show great promise to address grid problems through profit driven activities. I am pleased that the NOPR proposes to adopt a form of participant funding once independent transmission entities are in place. I am also pleased that the Commission is willing to consider proposals submitted by Regional State Advisory Committees for participant funding prior to nation-wide adoption. This order gives a push to state and regional entities that already have significant momentum and I hope to see the fruit of the Regional-State groups efforts in the form of actionable plans for cost allocation of expanded transmission. However, if these groups have difficulty getting organized and implemented, there is a default mechanism that would allocate the costs of expanded transmission locally if the facilities are below 138 kV and regionally if the facilities are above the 138 kV level. I urge the parties, especially the states, to carefully consider this section of the NOPR and comment on this. I still have some uncertainty whether we reached the right balance here.

Furthermore, the states have been asking for some time for certain responsibilities in RTOs, particularly in the area of reliability and planning. In SMD it is envisioned that they will play important roles in developing the resource adequacy standards and transmission expansion pricing methods. We will give deference to areas that are not as far along in standardizing markets, allowing states to manage the pace of the required changes. Additionally, the proposed rule, while it asserts jurisdiction over native load, does not abrogate either actual or implicit contracts. I am not so Pollyanna as to believe that everyone will be happy with our assertion of jurisdiction over native load, in fact this is likely to be a big bone of contention. But take a look at the rule, as I think states will find that it tries to be balanced and allows them significant say in determining outcomes.

Another area that I have focused on in this process is cost shifts. I agree that embedded costs charges for wheel through and export transactions should be eliminated or minimized while at the same time assuring recovery of the transmission owner's revenue requirement. My concern with respect to cost shifts resulting from this removal of inter-regional rates is two-fold.

First, I fear that areas with low-cost energy, such as my state of Kentucky, will see those resources flow to high-cost areas located several states or regions away. It is a mathematical fact that when costs are averaged that someone's costs will go up. This particular concern is in part alleviated by the ability for those in low-cost areas to lock up their low-cost power resources in long term contracts. I also note that these transactions which will flow over greater distances, now that they no longer face the fixed cost of the transmission system, will be subject to marginal losses and congestion charges. I believe that marginal losses in excess of actual losses should be credited back to the areas where the power originated.

My second concern with cost shifts relates to the determination of how these costs will be apportioned among different types of customers. Even if costs are allocated to import zones instead of to each ITP, one customer in the zone that relies solely on generation within the zone could subsidize a customer that imports all of its requirements. This is due to the fact that the embedded costs for imports would be spread across all load within the zone. My hope is that parties will comment on these and other costs shifts giving us concrete examples of the kind and level of shifts that may occur. I would also ask for recommendations on how best to address cost shifts, especially if they have a significant impact on retail customers.

In Order 888, Imbalance service was an ancillary service that could be provided by the transmission provider or it could be self-supplied. In staff's initial thinking on SMD as expressed in their concept paper, the markets for both real-time and day ahead energy would only require voluntary participation. As we worked through the details of SMD, this idea morphed a bit to now require imbalance service to be taken through the real-time energy market set up by the ITP. Participation in the day-ahead market is still left to the buyer's discretion and bilateral contracts are encouraged. But, the requirement for load to buy their imbalance service through the real-time market is a significant change. Loads will be subject to spot prices for that small portion of their load that varies from their load forecasts. I hope that parties will comment on this change to imbalance service.

I believe that one of the fundamental underpinnings of this rule is to give equal access to the transmission grid to all and I support that notion. However, I recognize that giving everyone equal access means that decisions will be made based on each party's willingness to pay. This means that the price certainty that we gave through Order 888 will disappear. But, this does not mean that all price certainty will disappear because SMD provides mechanisms for customers to use to hedge the volatility in transmission markets and in real-time markets. My concern is that both small players and less sophisticated players will have increased transaction costs and steep learning curves in finding their way through these markets and in hedging these price risks. I don't want this rule to result in two classes of SMD participants—those that know how to participate effectively and those that have difficulty and incur higher costs without competitive benefits.

Also, after consulting several economic textbooks, we have defined market power for the first time in an electric order as ''the ability to raise price above the competitive level''. We caveat that definition by stating that the determination of when to intervene in a market, *i.e.* when the price is significantly raised for a sustained period, will be incorporated into our triggers for intervention rather that the definition. I am not positive that we have the definition right and I hope that parties will let us know if they think we have used the right definition.

The three prongs of mitigation proposed in this NOPR, local market mitigation, a safety-net bid cap, and the resource adequacy requirement, along with the requirement for an active independent market monitor should protect these markets during what could be a rocky inception. My hope is that over time there will be less reliance on mitigation measures as the structural problems in these markets subside. Further, I believe this proposed rule holds promise for solving the disagreements that we have today on the ability to exercise market power under our current methods for granting market-based rates. With these stringent new mitigation measures in place the Commission should reassess its reliance on the Supply Margin Assessment test and study the need for the 206 refund obligation.

With respect to governance, I do not agree with the level of prescription that we are imposing on certain governance proposals. I don't think the Commission should be dictating with such specificity so many rules concerning the explicit makeup of stakeholder committees, who can sit on which committees, and exactly how boards should be selected. This could have the effect of disbanding boards of RTOs that are in the formative stages and boards that might have met our Order 2000 independence requirements.

And last, but definitely not least, I am pleased that today's proposed rule keeps the same provisions for reciprocity as that of the OATT. Entities that already have waivers of the reciprocity provision will not have to come in again and request additional waiver from the SMD provisions. Today's proposed rule also would allow reciprocal OATTs to be grandfathered and require no further changes to those tariffs to meet the new SMD requirements. This provides necessary relief to small transmission owners, including municipalities and cooperatives.

I urge my colleagues to carefully consider the comments and not be shy about considering changes to the proposal. We are asking over seventy-five questions which indicates that we still need industry's and the public's advice on a number of issues. I will be anxiously awaiting the comments and look forward to what parties have to say on these and other issues.

Linda K. Breathitt,
Commissioner.

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