17.1 Application: A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement. ***12473**

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

18 CFR § 35.19a

17.3 Deposit: A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point

Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR §35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application: Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transmission capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement: Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section , within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service: The Transmission Customer can obtain up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application: Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:
(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service: Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transmission Capability: Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transmission capability pursuant to Section ***12474** 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service. [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3 , shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications: Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities: The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service: If the Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in ***12475** writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

20 Procedures if The Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions: When the review process of Section determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions: If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions: The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service: Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service ***12476** occurs but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Parties through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service: In accordance with Section 4, Resellers may use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Point(s)

24.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data: The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. Network Integration Transmission Service

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service: Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available 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 the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service: The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service: The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System.

29 Initiating Service

29.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible ***12477** Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G.

29.2 Application Procedures: An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection), 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 Transmission Provider Control 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 Transmission Provider's Transmission System;
(vi) Description of Eligible Customer's transmission system:

—Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider

—Operating restrictions needed for reliability

—Operating guides employed by system operators

—Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources

—Location of Network Resources described in subsection (v) above

—10 year projection of system expansions or upgrades

—Transmission System maps that include any proposed expansions or upgrades

—Thermal ratings of Eligible Customer's Control Area ties with other Control Areas; and
(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities: The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement: The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

30 Network Resources

30.1 Designation of Network Resources: Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources: The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must ***12478** be made by a request for modification of service pursuant to an Application under Section 29.

30.3 Termination of Network Resources: The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

30.4 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus non-firm sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

30.5 Network Customer Redispatch Obligation: As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider: The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected with the Transmission Provider: This section applies to both initial designation pursuant to Section and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates: The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures For Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment . If the Transmission Provider determines that a System Impact

Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and ***12479** time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

33 Load Shedding and Curtailments

33.1 Procedures: Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints: During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement.

33.5 Allocation of Curtailments: The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding: To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability: Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission

Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good ***12480** Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth ($^1/_{12}$) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load: The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge: The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery: The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation under The Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the [applicable regional reliability council], (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and the [applicable regional reliability council] requirements. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee: A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Schedule 1—Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 2—Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Schedule 3—Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to ***12481** follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 4—Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

The Transmission Provider shall establish a deviation band of +/-1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider. If an energy imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer will compensate the Transmission Provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider. The charges for Energy Imbalance Service are set forth below.

Schedule 5—Operating Reserve—Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 6—Operating Reserve—Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the

Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 7—Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

(1) Yearly delivery: one-twelfth of the demand charge of $________/KW of Reserved Capacity per year.

(2) Monthly delivery: $________/KW of Reserved Capacity per month.

(3) Weekly delivery: $________/KW of Reserved Capacity per week.

(4) Daily delivery: $________/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Schedule 8—Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

(1) Monthly delivery: $________/KW of Reserved Capacity per month.

(2) Weekly delivery: $________/KW of Reserved Capacity per week.

(3) Daily delivery: $________/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $________/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must

occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Attachment A—Form of Service Agreement for Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of__________, is entered into, by and between __________ (the Transmission Provider), and __________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to ***12482** have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (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 Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider

Transmission Customer

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider

By:

Name

Title

Date

Transmission Customer

By:

Name

Title

Date

Specifications for Long-Term Firm Point-To-Point Transmission Service
1.0 Term of Transaction: ______________

Start Date:

Termination Date:
2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

3.0 Point(s) of Receipt: ______________

Delivering Party: ______________
4.0 Point(s) of Delivery: ______________

Receiving Party: ______________
5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

6.0 Designation of party(ies) subject to reciprocal service obligation:

7.0 Name(s) of any Intervening Systems providing transmission service:

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:

8.2 System Impact and/or Facilities Study Charge(s):

8.3 Direct Assignment Facilities Charge:

8.4 Ancillary Services Charges:

Attachment B—Form of Service Agreement For Non-Firm Point-To-Point Transmission Service
1.0 This Service Agreement, dated as of __________, is entered into, by and between __________(the Transmission Provider), and _________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider

Transmission Customer

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider

By:

Name

Title

Date

Transmission Customer

By:

Name

Title

Date

Attachment C—Methodology To Assess Available Transmission Capability

To be filed by the Transmission Provider.

Attachment D—Methodology for Completing a System Impact Study

To be filed by the Transmission Provider.

Attachment E—Index of Point-To-Point Transmission Service Customers

Customer

DATE of Service Agreement

Attachment F—Service Agreement for Network Integration Transmission Service

To be filed by the Transmission Provider.

Attachment G—Network Operating Agreement

To be filed by the Transmission Provider.

Attachment H—Annual Transmission Revenue Requirement for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be __________.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission. ***12483**

Attachment I—Index of Network Integration Transmission Service Customers

Customer
Date of Service Agreement

Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities. Docket No. RM95-8-001.

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Docket No. RM94-7-002.

(Issued March 4, 1997)

HOECKER, Commissioner, dissenting in part:

I. General Observations

Today's rehearing order makes Order No. 888 ripe for judicial review and largely concludes the most ambitious generic rulemaking effort in this agency's history. The scores of specific policy calls embodied in Order No. 888-A represent reasoned decisionmaking that, in its sheer level of detail, takes us to the outer limits of our ability to predict or control the proper future operation of the market. Still, the timeliness of this order ought to be welcomed. Having satisfactorily demonstrated that the fundamental rules governing a network as complex and important as the Nation's transmission grid can be changed and made to work, the Commission will henceforth be engaged in implementing open access tariffs and dealing with the direct and indirect consequences of bulk power competition. The mantle of major policymaking now shifts to the states and to the U.S. Congress.

During this proceeding, the industry has continued to evolve. In ten short months, merger and acquisition activity has increased dramatically and may foretell a more significant reconfiguration in the future. The concept of an independent system operator has attained significant credibility as a possible way to throttle market power, ensure system reliability, and rationalize the bulk power market. Retail access and customer choice suddenly dominate the restructuring debate, although the future competitive retail power market still defies prediction. The demarcation between state and federal jurisdiction is actively being tested. And, as the implications of full stranded cost recovery are being thought through within the industry, companies are also trying to diagnose and address their other competitive vulnerabilities. These remarkable and largely unforeseeable changes counsel against the temptation among public policymakers to over-plan and over-prescribe the future of power markets.

II. Partial Dissent

In Order No. 888, the Commission announced that it would be the "primary forum" for stranded cost claims in those instances where a retail power customer turns wholesale wheeling customer, usually through a municipalization. I dissented from that portion of the Final Rule because I concluded that the Commission's decision to take responsibility for stranded costs arising from municipalization was insupportable as a matter of either policy or law. As the "primary forum" for recovery of these costs, the Commission will be required to second-guess certain state retail stranded cost determinations, even when state regulators and state statutes address the issue sufficiently. This would, in my estimation, encourage forum shopping and fundamentally contradict our approach in the retail wheeling situation, where retail stranded costs are subject to Commission action only if the state regulatory body lacks authority to deal with this important transitional issue. I continue to hold these views.

The majority has bolstered its position today with additional arguments connecting the Commission's actions in Order No. 888 to the wholesale status of new municipal power customers. While inventive, the majority rests its theory of jurisdiction on a tenuous theory of cause and effect. Briefly, the rehearing order distinguishes wholesale stranded costs from retail stranded costs not by the nature of the costs, but by the status of the customer (i.e., a wholesale transmission services customer versus a retail transmission services customer) with whom the costs are associated. It further contends that jurisdiction over stranded costs depends on "whether the transmission tariffs used by the customer to escape its former power supplier * * * were required by this Commission or by a state commission". The majority states that this Commission will serve as the "primary forum" for stranded cost recovery only where there exists a direct nexus between the availability and use of FERC's open access transmission tariffs and the stranding of costs.

I am not persuaded by the rationale supplied by my colleagues. I continue to believe that municipalization, like retail wheeling, would be unavailable to retail customers as a competitive supply alternative but for state action. In both instances, it is state law that provides the legal means for retail customers to gain access to FERC-jurisdictional transmission tariffs. In the final analysis, I am not persuaded that the public interest is served by the majority's intrusion into an area potentially policed under state law, notwithstanding the Commission's strong commitment to full cost recovery.

In today's order, the Commission also broadens its "primary forum" approach to include situations involving the expansion of existing municipal utility systems, for example through annexation of retail customer load or additional service territory. I contend, however, that the "primary forum" approach is no more appropriate for municipal annexations than it is for new municipalizations.

The discussion of this issue in Order No. 888-A heightens my previous concerns in a number of ways. First, the majority's position is based on the alleged similarities between the creation of a new municipal utility system and the expansion of an existing municipal utility system. In both cases, they argue, a nexus exists between the municipalization and Commission-required transmission access; the salient connection is the use that the new wholesale customer makes of the former supplying utility's transmission system. If one were to assume the correctness of the majority's municipalization approach, it would make sense to limit its stranded cost recovery provisions to such circumstances only. But, there are two more compelling factors that determine the legitimacy of any stranded cost approach. First, like retail wheeling, all municipalizations, whether new or annexations, occur pursuant to state law. As already discussed, state action allows retail customers to aggregate load and, through municipalization, gain access to FERC-jurisdictional transmission tariffs. Second, the risk of annexation (and with it the loss of retail load) existed long before enactment of the Energy Policy Act or implementation of Order No. 888. I believe these factors argue for treatment of all costs incurred to serve retail load and stranded pursuant to state action—whether by retail wheeling, new municipalization, or annexation—by the same state regulatory body. I do not dispute, however, that the Commission should step in when states fail to ensure some level of stranded cost recovery, thereby creating a regulatory gap.

The rehearing order has an additional problem. It states that the Commission will not necessarily be the "primary forum" for stranded cost recovery in all cases of municipal annexation. The majority's new willingness to decide stranded costs arising from the annexation of new load will therefore require a finding that the existing municipality will use the transmission system of the annexed retail customers' former supplier to provide service to the annexed load. This approach is necessitated by the "nexus" theory of jurisdiction over the underlying stranded costs, and it represents a novel theory of law. Moreover, the administrative difficulties associated with this particular fact-finding will be extensive. An existing municipality already has transmission and generation service arrangements in place. With access to additional generation resources now available in the newly competitive wholesale power market, a municipality ultimately may be served by a number of suppliers, possibly in addition to its own resources. In such circumstances, the difficulty in determining which generation resources, and hence which transmission services, are being used to supply service to the annexed customers in particular may be virtually insurmountable. Under the nexus test, the Commission must settle that matter preliminarily just to decide whether it is the proper forum for addressing the costs stranded by an annexation.

To compound this practical problem, the majority's commitment to give "great weight to a state's view" of what stranded costs are recoverable under state law in these circumstances, and to deduct the amount of state stranded cost awards from the amount that a utility may seek to recover from this Commission, is likely to prove a hollow promise. Such deference would require a prior stranded cost determination on the merits by state regulators, despite the majority's instruction to the parties to raise all stranded cost claims under the municipalization scenario before this Commission "in the first instance." ***12484** Deference in this context is a slippery proposition for other reasons, too. Naturally, states may perceive equity considerations, cost causation principles, [FN1] and market risk factors[FN2] differently than the Commission, and consequently they may not share the Commission's view that utilities are entitled to full recovery of stranded costs here. Because of this potential difference of opinion, I suspect that the amount of deference that the Commission provides to the states may be directly proportional to the level of stranded cost recovery that states grant the utilities.

In sum, the majority's ingenious attempt to federalize stranded cost claims arising from municipalization, while admirable in terms of the need to resolve transition cost issues expeditiously, is more likely to cause greater uncertainty and more argument about the appropriate standard to apply than it is to promote settlement of the matter.

I therefore respectfully dissent in small part to Order No. 888-A.

James J. Hoecker,

Commissioner.

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities. Docket No. RM95-8-001.

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Docket No. RM94-7-002.

Order No. 888-A

(Issued March 4, 1997)

MASSEY, Commissioner, dissenting in part:
I dissent in part, from this otherwise excellent rule, on a single issue. I continue to believe, as I stated in my dissent to Order No. 888, that the Commission should treat stranded costs arising from retail competition and municipalizations similarly.

Municipalization occurs under state rather than federal law. The majority's decision in Order No. 888 that FERC should be the primary forum for addressing the recovery of stranded costs caused by municipalization boldly and unnecessarily preempts legitimate state authority. Today's order perpetuates and compounds this error by extending federal preemption to stranded costs arising from municipal annexations as well.

Many state commissions have express legislative authority to address these issues and should not be prohibited from doing so by federal regulators. It is only when a state commission does not have the authority, or has the authority and fails to use it, that the Commission should be available as a stranded cost recovery forum of last resort.

On this one issue, I respectfully dissent.

William L. Massey,

Commissioner.

[FR Doc. 97-5767 Filed 3-13-97; 8:45 am]

BILLING CODE 6717-01-P

Footnotes

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, clarified, 76 FERC 61,009 and 76 FERC 61,347 (1996). Order No. 889 is an accompanying rule and specific rehearing arguments on that rule will be addressed separately.

2 Under section 211 of the FPA, the Commission, on a case-by-case basis upon application by an eligible customer, may order both public utilities and non-public utilities that own or operate transmission facilities used for the sale of electric energy at wholesale to provide transmission services to the applicant if it finds it is in the public interest to issue such order.

3 61 FR 21540 at 21543; FERC Stats. & Regs. 31,036 at 31,638 (1996). No comments were filed [in objection to the public burden estimate contained in the Open Access Final Rule and the Stranded Cost Final Rule.

4 FERC Stats. & Regs. at 31,638-52; mimeo at 13-51.

5 As a condition of using a public utility's open access tariff, any user, including non-public utilities, must offer reciprocal comparable transmission access to the public utility in return. Order No. 888 provides a voluntary mechanism whereby non-public utilities can obtain Commission confirmation that what they are offering meets the tariff reciprocity condition. Non-public utilities also may seek a waiver of the reciprocity condition.

6 E.g., Nuclear Energy Institute, Southern, EEI. EEI and Nuclear Energy Institute also argue that Order No. 889 should not be severable.

7 FERC Stats. & Regs. at 31,654-56; mimeo at 57-61.

8 E.g., American Forest & Paper, Nucor, NY Municipal Utilities.

9 67 FERC 61,183 at 61,557 (1994).

FN10 FERC Stats. & Regs. at 31,656-57; mimeo at 63-66.

11 E.g., American Forest & Paper, SC Public Service Authority, TDU Systems, LEPA, San Francisco.

12 TDU Systems at 92.

13 We do not agree with entities that claim that our decision to rely on evidence raised by intervenors in particular cases with respect to transmission constraints improperly shifts the burden away from the utility, which has the greatest access to information concerning those constraints. Given that we have yet to see any evidence of generation dominance in long-term bulk power markets we do not believe that it is appropriate to burden all market-based rate applicants with significant information requirements as an initial matter. However, if an intervenor raises a specific factual concern with respect to a transmission constraint that may result in the exercise of market power in a particular case, we will examine those facts in a paper or formal hearing. In that context, the utility would be required to come forward with information sufficient to permit a full examination of the effect of the constraint on the applicant's ability to exercise market power.

14 FERC Stats. & Regs. at 31,660; mimeo at 73-75.

FN15 See, e.g., Southwestern Public Service Company, 72 FERC 61,208 at 61,996 (1995), reh'g pending.

FN16 The Final Rule contained a typographical error in which the word "not" was erroneously omitted.

17 FERC Stats. & Regs. 35,531 (1996).

FN18 FERC Stats. & Regs. at 31,661; mimeo at 77-78.

19 Order No. 592, Policy Statement Establishing Factors the Commission will Consider in Evaluating Whether a Proposed Merger is Consistent with the Public Interest, 77 FERC 61,263 (1996).

20 FERC Stats. & Regs. at 31,663-66; mimeo at 84-92.

21 The Commission defined these as contracts executed on or before July 11, 1994.

22 The Commission defined "existing" as those agreements executed prior to 60 days after publication of the Final Rule in the Federal Register.

FN23 The Commission defined "new" as those agreements executed 60 days after publication of the Final Rule in the Federal Register.

FN24 Accordingly, the Commission explained, transmission service needed for sales or purchases under all new economy energy coordination agreements will be pursuant to the Final Rule pro forma tariff

25 Utilities For Improved Transition, Union Electric, PSE&G, Carolina P&L.

FN26 Union Electric adds that there is no evidence that any existing economy energy coordination agreements are unduly discriminatory and require modification.

27 PSE&G at 6.

28 See also PSE&G.

29 See also Carolina P&L.

30 Blue Ridge at 16.

31 We note that the fact that a contract may bind a utility to a Mobile-Sierra public interest standard does not necessarily mean that the customer is also bound to that standard. Unless a customer specifically waives its section 206 just and reasonable rights, the Commission construes the issue in favor of the customer. See Papago Tribal Utility Authority v. FERC, 723 F.2d 950, 954 (D.C. Cir. 1983).

FN32 In situations in which a customer institutes a section 206 proceeding to modify a contract that binds the utility to a Mobile-Sierra public interest standard, the utility may make whatever arguments it wants regarding any of the contract terms, including those unrelated to stranded costs, but will be bound to a Mobile-Sierra public interest standard for contract terms that do not relate to stranded costs.

33 Similarly, as discussed in Section IV.J, parties have taken extreme positions as to stranded cost recovery.

34 As to existing economy energy coordination agreements, the Commission concludes that the evidence also supports its decision to condition future sales and purchase transactions that may occur under the ongoing umbrella coordination agreements. Specifically, we are requiring that the transmission service associated with these future transactions be provided pursuant to the Final Rule pro forma tariff. See Public Service Electric & Gas Company, 78 FERC 61,119, slip op. at 4 and n.7 (1997).

35 As discussed below, pre-July 11, 1994 contracts were entered into during an era in which transmission providers exerted monopoly control over access to their transmission facilities. The unequal bargaining power between utilities and captive customers is the basis for our determination that utilities that have pre-July 11 Mobile-Sierra requirements contracts will have to satisfy the public interest standard in order to effectuate any non-stranded cost change to the contract, but that customers to such contracts will be able to effectuate any change by satisfying a just and reasonable standard.

36 We will not grant the request by PSE&G and Carolina P&L that the just and reasonable standard will be limited to a determination of whether the rate is just and reasonable within the cost-based zone of reasonableness of the selling utility and should not include a comparison to what other utilities offer their customers. Because stranded costs will be taken into account when customers seek contract termination or modification, it would not be appropriate to limit customers in the evidence they may present.

37 We note that some of the very parties making this challenge either do not object to the Commission's Mobile-Sierra findings permitting utilities to add stranded cost amendments to their contracts, or ask the Commission to broaden even further the scope of extra-contractual stranded cost recovery under the rule.

FN38 We also reject arguments that a remedy is not needed because existing programs, i.e., those prior to Order No. 888, are meeting the needs of the industry. This very rulemaking, with the substantial comments filed by entities pointing out the failures of the current system and the need for change, and the extensive restructurings and state-initiated open access programs occurring around the country, on their face, refute these arguments.

FN39 It is also clear from the number of entities filing comments on the NOPR and rehearing requests of the Final Rule that many entities believe that their contracts were the result of uneven bargaining power and that they should be provided the opportunity to seek to terminate their existing contracts.

FN40 In an era that was not characterized by competition in the generation sector, the Commission's response was to ensure that the rates for such contracts were no higher than the seller's cost (including a reasonable return on equity). In this way, the Commission sought to limit the seller's ability to reap the benefits of the seller's monopoly position.

FN41 See FPC v. Sierra Pacific Power Company, 350 U.S. 348, 355 (1956); Northeast Utilities Service Company, 66 FERC 61,332 (1994), aff'd, 55 F.3d 686, 691 (1st Cir. 1995); Mississippi Industries v. FERC, 808 F.2d 1525, 1553 (D.C. Cir. 1987).

42 We will not exclude Mobile-Sierra contracts entered into after the effective date of EPAct, as argued by PSE&G and Carolina P&L. As we explained in the Final Rule, there are significant time delays associated with section 211 proceedings. Accordingly, the availability of a section 211 proceeding cannot substitute for readily available service under a filed non-discriminatory open access tariff. FERC

Stats. & Regs. at 31,646; mimeo at 35. We do not believe that EPAct created the expectation of open access on such a broad scale that we can assume that parties no longer generally expected "business as usual" to continue, and we will not presume that the exercise of market power was not at work when Mobile-Sierra contracts were entered into after EPAct. We also note that these arguments are similar to those proffered by opponents of stranded cost recovery, who argue that after EPAct utilities had no reasonable expectation of continuing to serve customers beyond the terms of existing contracts. In this context as well, we will not presume that, after EPAct, utilities could have no reasonable expectation of continuing to serve a customer beyond the contract term.

43 As the D C. Circuit explained in Papago Tribal Utility Authority v. FERC, 723 F.2d 950 (D.C. Cir. 1983) (Papago), there are essentially three contractual arrangements for rate revision: (1) the parties agree that the utility may file new rates under section 205, subject to the just and reasonable standard of review; (2) the parties agree to eliminate the utility's right to file rates under section 205 and the Commission's right to change pre-existing rates under section 206's just and reasonable standard (leaving the Commission's indefeasible right to change pre-existing rates that are contrary to the public interest); and (3) the parties agree to eliminate the utility's right to file new rates under section 205, but leave unaffected the Commission's power to change pre-existing rates under section 206's just and reasonable standard of review. 723 F.2d at 953. The same contractual arrangements also would apply to non-rate terms and conditions. We here address those contractual arrangements that eliminate the rights of one or both parties to modify a contract under the just and reasonable standard. We note that the Commission always has the indefeasible right under section 206 to change rates, terms or conditions that are contrary to the public interest. 723 F.2d at 953-55; see also Florida Power & Light Company, 67 FERC 61,141 at 61,398 (1994) appeal dismissed, No. 94-1483 (D.C. Cir. July 27, 1995) (unpublished); Southern Company Services, Inc., 67 FERC 61.080 at 61,227-28 (1994); Mississippi Industries v. FERC, 808 F.2d 1525. 1552 n.112.

FN44 We reject the arguments of PSE&G and Carolina P&L that we have failed to demonstrate the "unequivocal public necessity" for generically "abrogating" Mobile-Sierra clauses and that we have presented no evidence as to how the public interest will be served by abrogating these contracts. We have concluded that there is a public necessity to permit the opportunity to seek contract changes in light of fundamental industry changes. However, we have not abrogated any contracts by this Rule.

45 FERC Stats. & Regs. at 31,664; mimeo at 84.

46 FERC Stats & Regs. at 31,665; mimeo at 88.

FN47 The Commission explained that this right of first refusal exists whether or not the customer buys power from the historical utility supplier or another power supplier If the customer chooses a new power supplier and this substantially changes the location or direction of its power flows, the customer's right to continue taking transmission service from its existing transmission provider may be affected by transmission constraints associated with the change.

48 See also AEC & SMEPA

49 All transmission contracts with public utility transmitters can only be terminated by a filing with the Commission under FPA section 205. Thus, the Commission has interpreted its section 205 authority as permitting it to suspend termination of service for 5 months beyond the expiration of a contract's term if such action is necessary to protect ratepayers. See, e.g., Kentucky Utilities Company, 67 FERC 61,189 at 61,573 (1994). (While the termination procedures for power sales contracts executed after July 9, 1996 were modified in Order No. 888, there were no changes regarding termination procedures for transmission contracts.).

50 We clarify that we did not intend the term "all firm transmission customers" to include only requirements and transmission-only customers, but intended that it include all bundled firm customers as well.

FN51 We reject Tallahassee's argument that the right of first refusal should accrue to the power customer paying the bundled rate and not to any intermediary acting on its behalf. Our right of first refusal mechanism is simply a tie-breaker that gives priority to existing firm transmission customers.

52 The proposal to restrict the right of first refusal provision to exactly the same points of receipt and delivery as the terminating service would competitively disadvantage existing customers seeking new sources of generation. However, as we stated in Order No. 888, if the customer chooses a new power supplier and this substantially changes the location or direction of the power flows it imposes on the transmission provider's system, the customer's right to continue taking transmission service from its existing transmission provider may be affected by transmission constraints associated with the change. FERC Stats. & Regs. at 31,666 n.176; mimeo at 89 n.176.

53 As Order No. 888 indicates, they may be required to pay the transmission provider's maximum transmission rate.

54 FERC Stats. & Regs. at 31,665-66; mimeo at 89-90.

55 77 FERC 61,025.

56 FERC Stats. & Regs. at 31,665; mimeo at 87-88.

57 76 FERC 61,009 at 61,028 (1996).

58 FERC Stats. & Regs. at 31,668; mimeo at 96-98.

59 FERC Stats. & Regs. at 31,668-79 and 31,686-87; mimeo at 98-129 and 148-51.

60 Associated Gas Distributors v. FERC, 824 F.2d 981, 998 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988) (AGD).

FN61 Otter Tail Power Company v. FPC, 410 U.S. 366 (1974) (Otter Tail).

62 Richmond Power & Light Company v. FERC, 574 F.2d 610 (D.C. Cir. 1978) (Richmond) and Florida Power & Light Company v. FERC, 660 F.2d 668 (5th Cir. 1981), cert. denied sub nom. Fort Pierce Utilities Authority v. FERC, 459 U.S. 1156 (1983) (FPL).

63 We note that Indianapolis P&L also has made legal arguments regarding our authority to order wheeling under Order No. 888. However, it did so in a request for rehearing of a denial of its request for waiver of the Order No. 888 requirements, not in its request for rehearing of Order No. 888. Accordingly, we will address its arguments when we act on its request for rehearing of its waiver denial.

64 FERC Stats. & Regs. at 31,668-73; mimeo at 98-112. Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. 32,514 at 33,053-56 (1995).

FN65 FERC Stats. & Regs. at 31,673-79; mimeo at 112-129.

66 See FERC Stats. & Regs. at 31,669-70; mimeo at 101-03.

FN67 824 F.2d at 998.

68 See FERC Stats. & Regs. at 31,676-78; mimeo at 120-27.

69 See FERC Stats. & Regs. at 31,668-73; mimeo at 98-110.

70 See FERC Stats. & Regs. at 31,686-87; mimeo at 148-49.

FN71 The savings clause in section 212(e) originally provided that no provision of section 210 or 211 shall be treated as "limiting, impairing, or otherwise affecting any authority of the Commission under any other provision of law." In 1992, the 212(e) savings clause was amended to provide that sections 210, 211 and 214 "shall not be construed as limiting or impairing any authority of the Commission under any other provision of law."

72 AGD, 824 F.2d at 996-999. See also FERC Stats. & Regs. at 31,668-73, 31,676-78; mimeo at 98-110 and 120-27.

73 We do not repeat our lengthy legal analyses in Order No. 888, but discuss only those arguments that warrant further discussion.

FN74 See Union Electric and Carolina P&L

FN75 These authorizations are issued under section 7 of the Natural Gas Act and section 311 of the Natural Gas Policy Act.

FN76 While there is a difference in the statutes in that natural gas transporters must obtain a certificate from the Commission before they can transport gas, there is no difference in the statutory standard applied to the interstate service.

77 824 F.2d at 997-98. The court also noted the Commission's reliance on section 16 of the NGA.

78 824 F 2d at 993-94.

79 For example, as the AGD court explained with regard to its discussion of Maryland People's Counsel v. FERC, 761 F 2d 780 (D.C. Cir. 1985), "we made it clear that blanket-certificate transportation, unconstrained by any nondiscriminatory access provision, might well require remedial action under §5." 824 F.2d at 1000.

80 We disagree with Union Electric that anything in the Commission's brief to the Supreme Court, opposing certiorari of AGD, contradicts our conclusion. We recognize, as the Commission explained in that brief, that there is no equivalent to section 7 of the NGA in the FPA. While this puts Order No. 888 on a somewhat different factual basis from AGD, it has no material effect on whether we have the authority to remedy undue discrimination by requiring non-discriminatory open access transmission.

FN81 See 824 F.2d at 993-94 ("The Order envisages a complete restructuring of the natural gas industry. It may well come to rank with the three great regulatory milestones of the industry. * * *").

82 Parties have raised the legislative history of sections 205 and 206, as well as the legislative history of the EPAct amendments to sections 211 and 212.

FN83 FERC Stats. & Regs. at 31,676-78; mimeo at 120-27. Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. 32,514 at 33,053-56 (1995). Union Electric points to a statement in the Commission's 1987 brief to the U.S. Supreme Court, opposing certiorari of the AGD case; in that brief the Commission pointed out that the Supreme Court had noted, in Otter Tail, that the legislative histories of the FPA and NGA are "materially different " As we explained in Order No. 888, we have thoroughly reexamined the legislative histories of the NGA and FPA with respect to this issue and now conclude that there is no material difference as to this issue in the legislative histories of the two statutes. Further, such a difference, whether or not it exists, was not crucial to the fundamental holdings of the AGD court and does not preclude that decision from applying equally in the electric industry. See FERC Stats. & Regs. at 31,676-78; mimeo at 121-26. We also note that in its brief to the Supreme Court the Commission explicitly stated that neither Otter Tail nor any of the other electric cases cited "presented the question whether the Commission could order wheeling to remedy undue discrimination or anticompetitive behavior. * * *" FERC Brief at 25 (footnote omitted).

84 See discussion supra concerning AGD court's understanding that Order No. 436 was not a simple order that relied on voluntary actions of affected pipelines

FN85 Contrary to certain assertions, in Order No. 888 we viewed the statute as a whole and determined that section 211 in no way limited the broad authority Congress gave us to eradicate undue discrimination in the electric power industry.

FN86 See note 71 and related discussion, supra.

FN87 In response to Carolina P&L's argument that Congress gave the Commission a specific remedy under section 211 and the Commission should not presume that it has additional remedies in such a circumstance, we do not believe that section 211 can credibly be viewed either as a partial substitute for, or as superseding, the sections 205-206 undue discrimination remedial authority that is fundamental to the Federal Power Act. Indeed, section 211 is not written in terms of providing remedial authority to address undue discrimination but rather provides for case-by-case transmission service on request if the service is in the public interest and meets the other criteria in sections 211 and 212.

88 FERC Stat. & Regs. at 31,686-87; mimeo at 148-51.

89 Most of the statements talk in terms of "The Conference Report provides. . . ." and thus are referring only to the section 211 and 212 provisions. See, e.g , 138 Cong. Rec. 517616 (Oct. 8, 1992).

90 FERC Stats. & Regs. at 31,676-78; mimeo at 120-27.

91 FERC Stats. & Regs at 31,670; mimeo at 103.

92 Union Electric at 26.

93 FERC Stats. & Regs. at 31,677; mimeo at 122.

94 Union Electric at 27.

95 Union Electric at 30.

FN96 The only relevant case the AGD court did not discuss was NYSEG. As we explained in Order No. 888, presumably this was because the case did not concern whether the Commission could order wheeling as a remedy for undue discrimination. FERC Stats. & Regs. at 31,672 n.217; mimeo at 108 n.217.

97 Union Electric at 33-37.

98 Union Electric at 37-40.

FN99 Union Electric at 38-39.

FN100 Hearings on H.R. 1301, H.R. 1543, and H.R. 2224 before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, 102d Cong., 1st Sess. (May 1, 2 and June 26, 1991), Statement of Cynthia A. Marlette, Associate General Counsel, Federal Energy Regulatory Commission, Report No. 102-60 at 60 ("However, as discussed below, there are strong legal arguments that the Commission's obligation to protect against undue discrimination carries with it the authority to impose transmission requirements as a remedy for undue preference or discrimination." "As discussed below, although the case law in this area has been uncertain, in OGC's opinion there is a strong legal argument that the Commission can require transmission as a remedy for undue preference or undue discrimination."); at 69-70 ("The weight of the limited case law, particularly the AGD opinion, supports authority to order wheeling as a remedy for undue discrimination where substantial evidence exists."); at 106 ("I believe that we have substantial authority under the existing case law to mandate access where necessary to remedy anticompetitive effects.").

FN101 The statement quoted was preceded by a legal analysis of the Commission's authorities under then existing law, including section 206, and a statement that an examination of the Commission's full authorities might further open up the industry. Further, it was made in the context of case-by-case industry proposals and the Commission's inability to require case-by-case wheeling on its own motion. It did not address section 206 authority to remedy undue discrimination.

FN102 Union Electric at 39. We note that Union Electric did not cite to any page or particular language to support its assertion.

103 Carolina P&L at 35-36.

104 824 F.2d at 1001. In this regard, we acknowledge that our view of what constitutes undue discrimination has evolved significantly in light of the dramatic economic changes in the industry, as described briefly above and more fully in Order No. 888.

105 FERC Stats. & Regs. at 31,682-84; mimeo at 136-42.

106 E.g., El Paso, Union Electric, Carolina P&L, VA Com, FL Com, PA Com.

107 In response to PA Com's and Carolina P&L's assertions that not coming forward with specific accusations and identities of specific accusers is unconstitutional and a deprivation of due process, we emphasize that the Commission has not denied due process to anyone. The Final Rule does not, nor is it intended to, make specific findings as to any particular utility or any particular allegation raised.

108 FERC Stats. & Regs. at 331,682; mimeo at 136-37.

109 See AGD, 824 F.2d at 999-1000.

110 New England Power Pool, 67 FERC 61,402 (1994) (NEPOOL), American Electric Power Service Corporation, 64 FERC 61,279 (1993), reh'g granted, 67 FERC 61,168, clarified, 67 FERC 61,317 (1994) (AEP).

FN111 67 FERC 61,042 at 61,132.

FN112 Id.

113 Commonwealth Edison Co., 70 FERC 61,204 (1995); Wisconsin Electric Power Co., 70 FERC 61,074 (1995); and Wisconsin Public Service Corp., 70 FERC 61,075 (1995)

FN114 FERC Stats. & Regs. 32,524 at 33,079.

115 FERC Stats. & Regs. at 31,690; mimeo at 160.

116 There is no "requirement" in the FPA that the Commission apply a "similarly situated" test. Carolina P&L's reliance on City of Vernon is misplaced. That case involved a claim of discrimination in the type of service offered to a wholesale customer versus that offered to retail customers, and the Commission's application of the "similarly situated" and "same service" test. Contrary to Carolina P&L's implication, the case does not hold that the Commission is bound to apply a "similarly situated" test in analyzing undue discrimination claims under the FPA.

117 I.e., investor-owned utilities that owned generation, transmission and distribution facilities and most of whom had captive customers. FN118 Very simply, the transmission owner was able to prevent third parties from achieving the maximum savings possible in the generation market by withholding or delaying transmission service. Alternatively, the transmission owner could purchase the power and resell it to the third party at a rate that reflected a mark-up from the first power sale.

119 FERC Stats. & Regs. at 31,688-90; mimeo at 154-58.

120 E.g., SoCal Edison, PSE&G, Carolina P&L.

121 See also CSW Operating Companies.

122 FERC Stats. & Regs. at 31,689-90; mimeo at 158.

123 We also disagree with NYSEG's assertion that the right of first refusal provision would permit a retail customer receiving wheeling service to continue to receive service after the expiration of its contract and could require the transmission provider to continue wheeling beyond the scope of its voluntary offer of service or beyond the scope of a state-mandated retail access program. Section [212(h) of the FPA would override any provision, including the right of first refusal provision, that may be included in the pro forma tariff

124 FERC Stats. & Regs. at 31,780 and Appendix G (31,966-81); mimeo at 428 and Appendix G.

FN125 75 FERC 61,356 at 62,141, order on reh'g, 77 FERC 61,135 (1996). In the order on rehearing, the Commission permitted a separate retail tariff to remain in effect for the duration of the retail electric pilot programs established in Massachusetts by Massachusetts Electric Company.

15 See Open Access Rule, FERC Stats. & Regs. at 31,784; New Hampshire Interim Order, 75 FERC at 61,687 & n.3 (both noting that such a separate retail tariff must be consistent with the Commission's open access policies and comparability principles). * * *

126 76 FERC at 61,024.

127 FERC Stats. & Regs. at 31,770 n. 514; mimeo at 399 n. 514.

128 To the extent the transmission takes place on the interstate facilities of other public utilities, we would have jurisdiction over such transmission.

FN129 Native load means " [t]he 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." Section 1.19 of the pro forma tariff.

FN130 All transmission in interstate commerce by a public utility in conjunction with a sale for resale of electric energy is jurisdictional and must be taken under a FERC-jurisdictional tariff. The same is true for all unbundled transmission in interstate commerce to wholesale customers, as well as to unbundled retail customers.

131 Under the Order No. 888 pro forma tariff, third-party wholesale customers have the ability to obtain the identical service the transmission provider provides itself when it engages in a sale of electric energy for resale. This may include network or point-to-point service.

FN132 69 FERC) 61,145 at 62,300 (1994) (proposed order), 74 FERC) 61,220 (1996) (final order).

133 FERC Stats. & Regs. at 31,690; mimeo at 160.

134 FERC Stats. & Regs. at 31,690; mimeo at 160.

135 FERC Stats. & Regs. at 31,691-92; mimeo at 162-65.

136 See Policy Statement Regarding Regional Transmission Groups, 64 FERC 61,139 at 61,993 (1993); Midwest Power Systems, Inc., 69 FERC 61,025 at 61,104-05 (1994). Nor does the form of ownership of the joint facilities have any bearing on the Commission's jurisdiction over public utilities.

FN137 Though the non-jurisdictional entity would not become subject to Commission regulation.

FN138 Cf. H.K. Porter Co., Inc. v. Central Vermont Railway, Inc., 366 U.S. 272, 273-75 (1961).

139 FERC Stats. & Regs. at 31,693; mimeo at 168-70.

140 FERC Stats. & Regs. at 31,694; mimeo at 172.

141 FERC Stats. & Regs. at 31,694; mimeo at 172.

142 FERC Stats. & Regs. at 31,696; mimeo at 178-179.

143 FERC Stats. & Regs. at 31,696; mimeo at 179.

144 FERC Stats. & Regs. at 31,696-97; mimeo at 179-80.

145 FERC Stats. & Regs. at 31,697; mimeo at 180-81.

146 FERC Stats. & Regs. at 31,697; mimeo at 181.

147 VT DPS at 47-48; see also Valero at 29-31.

148 CCEM makes this argument in its rehearing request of Order No. 889.

149 While portions of network transmission service are not reassignable, we would permit the reassignment of a particular network transmission service in its entirety.

FN150 We note that the question of how network service may be converted into a service that is reassignable is at issue in the Capacity Reservation Tariff NOPR proceeding in Docket No. RM96-11-000.

151 We note that if the assignor is a public utility it will in any event have to file a rate schedule for the re-sale (reassignment) of unbundled transmission

152 We also reject as unsupported EEI's comparability argument that transmission providers must treat any transmission service revenues as a revenue credit, but the reseller may keep any transmission resale revenues.

153 In response to Carolina P&L's request, we clarify that the assignor is not limited to recovering the opportunity costs to which it is subject under the transmission provider's tariff, i.e., the transmission provider's opportunity costs.

154 FERC Stats. & Regs. at 31,698; mimeo at 183-84.

155 FERC Stats & Regs. at 31,699; mimeo at 186.

156 FERC Stats. & Regs. at 31,699-700; mimeo at 188.

157 FERC Stats. & Regs. at 31,781; mimeo at 430-31 (emphasis in original). As discussed in Section IV.I., infra, we believe this jurisdictional determination is supported by the statute and the case law, including the D.C. Circuit's recent decision in United Distribution Companies v. FERC, 88 F.3d 1105 (1996).

158 FERC Stats. & Regs. at 31,781; mimeo at 431.

159 FERC Stats. & Regs. at 31,700-01; mimeo at 191. See also discussion infra at Section IV.G. Section 1.11 (and Section 13.3).

FN160 By notice issued September 27, 1996 in Docket Nos. RM95-8-000 and RM94-7-001, the Commission revised the compliance dates. It required joint pool-wide section 206 compliance tariffs to be filed no later than December 31, 1996, and pool members to begin taking service under the tariffs 60 days after the section 206 filing It also gave members of public utility holding companies an extension of time to take service under their system-wide tariff until no later than March 1, 1997.

161 FERC Stats. & Regs. at 31,703; mimeo at 198.

162 FERC Stats. & Regs. at 31,703-04; mimeo at 199.

FN163 In comments on the proposed rule, NERC identified additional interconnected operations services that it indicated may be necessary for reliability. As discussed in the Final Rule, we do not require the transmission provider to be the default provider of these other services.

164 FERC Stats. & Regs. at 31,716; mimeo at 238.

165 FERC Stats. & Regs. at 31,716-17; mimeo at 239.

166 See also Cajun. Cajun notes that it does and could continue to provide at least a portion of reactive power.

167 See also APPA.

168 The location and operating capabilities of the generator will affect its ability to reduce reactive power requirements.

169 FERC Stats. & Regs. at 31,717; mimeo at 240.

170 Order No. 888 imposes no obligation on the transmission provider to furnish replacement power on a long-term basis if the customer loses its source of supply.

171 FERC Stats. & Regs. at 31,711; mimeo at 222.

FN172 FERC Stats. & Regs. at 31,711; mimeo at 223.

173 Many provisions regarding the reliable operation and performance of both generation and load will be included in supply interconnection agreements and transmission customer service agreements. The fact that we have designated six services as necessary to prevent undue discrimination in transmission service should not be interpreted as our having set out a complete set of interconnected operations services and conditions necessary for reliable and orderly bulk power system management.

174 E.g., APPA, NRECA, Blue Ridge, Cooperative Power, Wabash, TDU Systems, Redding, TAPS.

FN175 See also TDU Systems.

FN176 E.g., NRECA, Blue Ridge, Cooperative Power, Wabash.

177 E.g., TDU Systems, TAPS, NRECA, Wabash, Redding.

178 On the other hand, Wabash argues that pursuant to industry practice, overdeliveries should be treated differently than underdeliveries outside [the deviation band. It adds that the rate for underdeliveries should be cost-based.

179 FERC Stats. & Regs at 31,719; mimeo at 246.

180 See Order on Non-Rate Terms and Conditions. 77 FERC 61,144 at 61,538 (1996). The Commission explained:

Order No. 888 required all tariff compliance filings to contain non-rate terms and conditions identical to the pro forma tariff, with a limited exception for regional practices, and with four attachments where the utility could propose specific inserts.

FN181 FERC Stats. & Regs. at 31,770 n.514; mimeo at 399 n.514.

182 As NERC and others pointed out in their comments on the proposed rule, this service can be provided only by the operator of the control area in which the transmission facilities used are located. FERC Stats. & Regs. at 31,716; mimeo at 238.

183 In Docket No. ER95-791 the Commission ruled that this issue was not part of the hearing and that North Jersey should file for a declaratory order to resolve the matter.

184 FERC Stats. & Regs. at 31,720-21; mimeo at 250-52.

185 In brief, these are that (1) any offer of a discount made by the transmission provider must be announced to all potential customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for one's own use or for an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. In addition to these three principal requirements, we also require that a discount agreed upon for a path must be extended to certain other paths described in Section IV.G.1.h.

FN186 "Negotiation" would only take place if the transmission provider or potential customer seeks prices below the ceiling prices set forth in the tariff.

187 FERC Stats. & Regs. at 31, 722; mimeo at 255-56.

188 FERC Stats. & Regs. at 31,725-27; mimeo at 266-70.

189 FERC Stats. & Regs. at 31,727-28; mimeo at 270-72.

FN190 By notice issued September 27, 1996, the Commission extended the date by which public utilities that are members of tight power pools must take service under joint pool-wide open access transmission tariffs from no later than December 31, 1996 to 60 days after the filing of their joint pool-wide section 206 compliance tariff.

191 It is not clear from the rehearing request exactly how the current members of MECS are proposing to remove all transmission functions from pool control and to take transmission service under their individual open access tariffs. For example, this may preclude the continuation of joint economic dispatch of generating facilities belonging to Consumer Power and Detroit Edison, which the rehearing request appears to assume would continue. However, the Commission will address the adequacy of any such proposal in the context of the appropriate compliance filings.

191 FERC Stats. & Regs. at 31,657; mimeo at 64-65, section 35.27.

FN193 FERC Stats. & Regs. at 31,660; mimeo at 73-74.

194 See FERC Stats. & Regs. at 31,727-28; mimeo at 271-72.

195 FERC Stats. & Regs. at 31,728; mimeo at 272-74.

FN196 By notice issued September 27, 1996, the Commission extended the date by which public utility members of loose power pools must take service under joint pool-wide open access transmission pro forma tariffs from no later than December 31, 1996 to 60 days after the filing of their joint pool-wide section 206 compliance tariff.

197 See also Public Service Co of CO.

198 See FERC Stats. & Regs. at 31,728; mimeo at 273-74.

199 See FERC Stats. & Regs. at 31,726; mimeo at 268-69 (filing of open access tariffs by public utility pool members is not enough to cure undue discrimination in transmission if those entities can continue to trade with a selective group within a power pool; the same holds true for certain bilateral arrangements allowing preferential pricing or access) and FERC Stats. & Regs. at 31,727-28; mimeo at 270-272 (tight and loose pools must file joint pool-wide tariffs).

FN200 See FERC Stats. & Regs. at 31,730; mimeo at 278.

201 FERC Stats. & Regs. at 31,728-29; mimeo at 274-77.

202 By notice issued September 27, 1996, the Commission extended the date by which public utilities that are members of holding companies must take service under their system-wide tariffs from December 31, 1996 to no later than March 1, 1997.

203 AL Com at 1-4.

204 The Commission notes that Order No. 888 requires that all third party tariff customers taking network or point-to-point service pay a transmission rate which reflects an appropriate share of transmission costs, including those related to transmission construction.

FN205 FERC Stats. & Regs. at 31,729, mimeo at 277.

206 FERC Stats. & Regs. at 31,729-30; mimeo at 277-78.

207 Anaheim, in an answer opposing SoCal Edison's request for clarification regarding its package agreements, requests that these agreements be dealt with on a case-by-case basis "in context." (Anaheim Answer). While answers to requests for rehearing generally

are not permitted, we will depart from our general rule because of the significant nature of this proceeding and accept the Anaheim Answer.

208 See also VEPCO.

209 See also Florida Power Corp (if the Commission requires an unbundled transmission rate, it must allow transmission providers to reformulate their unbundled economy energy agreements to recover both their capacity and energy costs and the costs of transmission).

210 FERC Stats. & Regs. at 31,730; mimeo at 277.

211 FERC Stats. & Regs. at 31,730; mimeo at 277.

FN212 Approximately 300 filings to unbundle this category were filed by December 31, 1996.

213 FERC Stats. & Regs. at 31,666; mimeo at 90.

FN214 Regarding CCEM's request that non-economy energy coordination agreements be identified in determining available transfer capacity (ATC), we note that all data used to calculate ATC and total transfer capacity (TTC) must be made publicly available upon request pursuant to section 37.6(b)(2)(ii) of the OASIS regulations.

215 FERC Stats. & Regs. at 31,726; mimeo at 268-69.

FN216 See e.g., Illinois Power Company, 62 FERC 61,147 at 62,062 (1993).

217 FERC Stats. & Regs. at 31,730-32; mimeo at 279-86.

218 Sithe, in a response to the NYPP's request for clarification, opposes the "transmission owners only" ISO sought by NYPP. (Sithe Response). Subsequently, NYPP filed an objection to Sithe's pleading and request that it be rejected. (NYPP Objection). NYPP explains that its rehearing was a request that the Commission refrain from setting fixed rules for ISO governance in advance, not an argument that the Commission should adopt one particular mechanism or another for all ISOs. While answers to requests for rehearing generally are not permitted, we will depart from our general rule because of the significant nature of this proceeding and accept the Sithe Response and NYPP Objection.

219 Atlantic City Electric Company, et al., 77 FERC 61,148 (1996) (mimeo at 36-41); see also Pacific Gas & Electric Company, 77 FERC 61,204 (1996).

220 In making this finding, we are not suggesting that an independent transmission company, which owns only transmission, is undesirable. However, an ISO, which separates ownership and operation, is designed in large part to recognize that transmission owners today have significant generation or load interests that may bias their operational decisions.

221 FERC Stats. & Regs. at 31,731; mimeo at 283.

222 FERC Stats. & Regs. at 31,733; mimeo at 288-89.

FN223 FERC Stats. & Regs. at 31,733; mimeo at 289.

224 FERC Stats. & Regs. at 31,734-35; mimeo at 291-93.

225 FERC Stats. & Regs. at 31,751; mimeo at 342-43.

FN226 See Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC 61,006 at 61,013 and n.70 (1996).

227 E.g., FPL, Utilities For Improved Transition, TDU Systems, Carolina P&L, AEC & SMEPA, VT DPS, EEI.

228 FERC Stats. & Regs. at 31,751; mimeo at }342-43.

229 FERC Stats. & Regs. at 31,736; mimeo at }296-97.

230 Behind-the-meter generation means generation located on the customer's side of the point of delivery.

231 E.g., NRECA, TDU Systems, Blue Ridge.

232 FERC Stats. & Regs. at 31,736; mimeo at 297.

233 These entities do not explain how the Commission could force non-public utility control area operators, of which there are approximately 62 out of 138 in the United States (as of October 1996), to accede to these pricing policies.

234 E.g., Utilities For Improved Transition, Florida Power Corp, VEPCO.

235 FERC Stats. & Regs. at 31,736; mimeo at 296-97.

236 FERC Stats. & Regs. at 31,770; mimeo at 398-99.

237 E.g., AMP-Ohio, TAPS.

238 See FERC Stats. & Regs. at 31,736 and 31,743; mimeo at 297 and 317.

FN239 E.g., TAPS, Central Minnesota Municipal.

240 Utilities For Improved Transition argues that a transmission dependent utility should be required to serve its load using only network transmission service. It asserts that such a utility should not be allowed to avoid its full cost responsibility by using point-to-point firm during peak periods and non-firm service during non-peak periods. See also VEPCO.

Moreover, FMPA filed an answer in opposition to the requests for clarification of FP&L, Carolina P&L and others concerning the definition of network load and related issues. (FMPA Answer). Likewise, Michigan Systems and TAPS filed answers opposing these requests for rehearing. (Michigan Systems Answer and TAPS Answer). While answers to requests for rehearing generally are not permitted, we will depart from our general rule because of the significant nature of this proceeding and accept the FMPA Answer, Michigan Systems Answer and TAPS Answer.

241 FERC Stats. & Regs. at 31,736; mimeo at 297.

242 FMPA II at 61,012 (emphasis added)

243 FMPA II at 61,011.

244 The load-ratio cost responsibility is based on the network customer's monthly contribution to the transmission system peak (i.e., coincident peak billing).

245 FMPA at 3-4.

FN246 While this customer could lower its coincident peak use of the transmission system, it could be making substantial use of the transmission system during all other hours of the month but yet have little or no load-ratio cost responsibility.

247 Customers taking network integration transmission service choose to have the transmission provider integrate their generation resources with their loads. Network service is a service comparable to the service that the transmission provider provides to its retail native load, where the Transmission Provider includes the network customers resources and loads (projected over a minimum ten-year period) into its long-term planning horizon. Because network service is usage based, network customers pay on the basis of their total load, paying a load-ratio share of the costs of the transmission provider's transmission system on an ongoing basis. In contrast, point-to-point transmission service is more transitory in nature. Point-to-point service is frequently tailored for discrete transactions for various time periods, which may or may not enter into the transmission provider's planning horizon. A point-to-point transmission service customer is only responsible for paying for its reserved capacity on a contract demand basis over the contract term.

248 We also clarify that while the tariff prohibits the designation of only part of the load at a discrete point of delivery, this prohibition also applies to network customers with a discrete load served by multiple points of delivery. In other words, for the same reasons explained above, a customer may not choose to have part of a discrete load served under network integration service at one or more delivery points and at the same time have the remaining portion of the same load served under point-to-point transmission service at other delivery points.

FN249 An example of excluding the entirety of a discrete load would be a municipal power agency excluding the entire load of a member city with generation behind the meter, while requesting network service to serve the remaining member cities' loads. The excluded load of the member city must be met using a combination of generation behind the meter and any remote generation that may be necessary. The member city would be responsible for arranging any point-to-point transmission service under the pro forma tariff that may be necessary to import the power and energy from any remote generation.

250 E.g., NRECA, TDU Systems, AEC & SMEPA.

251 NRECA at 78-79; TDU Systems at 32.

252 Clearly, any such modification of existing contracts would required the agreement of all parties and a filing with the Commission.

253 FERC Stats. & Regs. at 31,737-38; mimeo at 301-04.

254 FERC Stats. & Regs. 31,005 (1994).

255 See also NE Public Power District.

256 FERC Stats. & Regs. at 31,736; mimeo at 296-97.

257 FERC Stats. & Regs. at 31,738; mimeo at 303.

258 Northeast Utilities Service Company (Northeast Utilities), 56 FERC 61,269 (1991), order on reh'g, 58 FERC 61,070, reh'g denied, 59 FERC 61,042 (1992), order granting motion to vacate and dismissing request for rehearing, 59 FERC 61,089 (1992), aff'd in relevant part and remanded in part, Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993); Pennsylvania Electric Company (Penelec), 58 FERC 61,278 at 62,871-75, reh'g denied, 60 FERC 61,034 (1992), aff'd, Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993).

259 The Commission has effectively achieved this result for opportunity sales by requiring separation of the transmission provider's wholesale merchant from its transmission operation employees.

260 These arguments include those made by VT DPS concerning Northeast Utilities and alleged inconsistencies with our natural gas policies.

261 Under the Commission's transmission pricing policy, utilities are limited to charging the higher of embedded costs or opportunity/incremental costs. See Order on Reconsideration and Clarifying Policy Statement, 71 FERC 61,195 (1995). Opportunity costs are capped by incremental expansion costs. Opportunity costs are viewed as a form of incremental or marginal cost pricing and include. (1) out-of-rate costs or costs associated with the uneconomic dispatch of generating units necessary to accommodate a transaction; and (2) costs that arise from a utility having to reduce its off-system purchases or sales in order to avoid a potential constraint on

the transmission grid. We note that Order No. 888 requires that off-system sales by the transmission provider must be made under the point-to-point provisions of the pro forma tariff.

If a utility expands its transmission system so that it can provide the requested transmission service, it can charge the higher of its embedded costs or its incremental expansion costs. When a transmission grid is constrained and a utility does not expand its system, the Commission has allowed a utility to charge transmission-only customers the higher of embedded costs or legitimate and verifiable opportunity costs ("or" pricing), but not the sum of the two ("and" pricing).

262 FERC Stats. & Regs. at 31,739-40; mimeo at 307-09.

263 FERC Stats. & Regs. at 31,740; mimeo at 309.

264 E.g , Utilities For Improved Transition, Florida Power Corp, VEPCO.

265 FERC Stats. & Regs. at 31,739; mimeo at 307-08.

266 FERC Stats. & Regs. at 31,767; mimeo at 388.

267 FERC Stats. & Regs. at 31,741; mimeo at 312-13.

268 E.g., Utilities For Improved Transition, Florida Power Corp, VEPCO.

269 FERC Stats. & Regs. at 31,742-43; mimeo at 316-18.

FN270 Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC 61,006 (1996), reh'g pending.

271 E g., NRECA, Blue Ridge, TDU Systems.

272 E.g., NRECA, TDU Systems, TAPS.

273 E.g., IMPA, TAPS, AMP-Ohio, Michigan Systems.

274 FERC Stats. & Regs. at 31,742; mimeo at 316.

FN275 Wisconsin Municipals' argument with respect to prior settlements has been previously addressed in Section IV.D.1.c.(2) (Energy Imbalance Bandwidth).

276 See FERC Stats. & Regs. at 31,742-43; mimeo at 316-17.

FN277 As we noted in FMPA II, this fundamental cost allocation concept applies to the transmission provider as well. Just as the customer cannot secure credit for facilities not used by the transmission provider to provide service, the transmission provider cannot charge the customer for facilities not used to provide transmission service.74 FERC 61,006 at 61,010 n.48 (1996).

FN278 FERC Stats. & Regs. at 31,742-43; mimeo at 317.

279 FERC Stats. & Regs. at 31,743-44; mimeo at 319-20.

280 All offers or agreements to provide rate discounts to affiliates (including the Transmission Provider's wholesale merchant) on a particular path must be posted immediately on the OASIS and be available for a long enough period to allow non-affiliates to obtain the same discounted service on that path and on other paths for which the transmission provider must provide the same discount. We modify below our requirement regarding which other paths must receive the same discount.

FN281 The Commission also stated that the same requirements will apply to discounts for firm transmission service. The Commission added that if a transmission provider offers an affiliate a discount for ancillary services, or attributes a discounted ancillary service rate to its own transactions, it must offer at the same time the same discounted rate to all eligible customers. The Commission noted that discounted ancillary services rates must be posted on the OASIS pursuant to Part 37 of the Commission's regulations.

282 E.g., SoCal Edison, Entergy, Southwestern, PacifiCorp, Montana Power, AEP, Utilities For Improved Transition, EEI.

283 See also Washington Water Power.

284 E.g., Montana Power, Allegheny, Puget.

285 See also Florida Power Corp.

286 We clarify that own use/affiliate transactions include all transactions where the transmission provider or any of its affiliates is either the buyer, seller, marketer, or broker of wholesale power.

FN287 "Negotiation" would only take place if the transmission provider or potential customer seeks prices below the ceiling prices set forth in the tariff.

288 For example, requiring the transmission provider to wait to see if an offered 5% discount clears the market would appear to be less efficient than permitting the customer to advise the transmission provider (via the OASIS) of its need for a higher discount in order to take service.

289 Thus, there is no need to revise contracts to reflect later offered discounts.

290 See also Valero.

291 Arizona Public Service Company, Order Addressing Functional Unbundling Issues, 78 FERC 61,016 (slip op. at 11) (1997) (Arizona).

292 FERC Stats. & Regs. at 31,745; mimeo at 323-24.

293 FERC Stats. & Regs. at 31,746-47; mimeo at 326-29.

294 FERC Stats. & Regs. at 31,694; mimeo at 172.

FN295 FERC Stats. & Regs. at 31,665 and 31,694, mimeo at 88 & 172.

296 FERC Stats. & Regs. at 31,748; mimeo at 332-33.

297 In the Final Rule pro forma tariff, the Commission defines curtailment as: "A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions." (pro forma tariff section 1.7). The pro forma tariff defines interruption as: "A reduction in non-firm service due to economic reasons pursuant to Section 14.7." (pro forma tariff section 1.15). The distinction between curtailment and interruption may have been blurred in Order No. 888 and this order attempts to clarify that distinction.

298 FERC Stats. & Regs. at 31,749; mimeo at 335-36.

299 E.g., Santa Clara, Redding, TANC.

300 FERC Stats. & Regs. at 31,749; mimeo at 335.

301 We note that in Order No. 888 we partially modified existing economy energy coordination agreements. FERC Stats. & Regs. at 31,666; mimeo at 91.

302 69 FERC 61,145 at 62,300 (1994) (proposed order), 74 FERC 61,220 (1996) (final order).

FN303 FERC Stats. & Regs. at 31,750; mimeo at 338-39.

304 A firm point-to-point customer has a right to change its receipt points if capacity is available. These changed receipt points are known as secondary receipt points. The issue addressed here is the priority that is assigned to those secondary receipt points.

305 See also Tallahassee.

306 FERC Stats. & Regs. at 31,750; mimeo at 338.

307 FERC Stats. & Regs. at 31,769-70; mimeo at 395-99.

FN308 We note that CCEM has pursued these arguments (raised on rehearing) in utility-specific rate cases and its objections will be addressed there.

309 See FERC Stats. & Regs. at 31,750; mimeo at 338, and AES Power, Inc., 69 FERC 61,145 at 62,300 (1994) (proposed order), 74 FERC 61,220 (1996) (final order).

FN310 This is comparable to the service a utility provides its native load.

311 FERC Stats. & Regs. at 31,760-63; mimeo at 370-378.

312 See 26 U.S.C. §141. Interest on private activity bonds is taxable unless the bonds are qualified bonds for which a specific exception is included in the Internal Revenue Code.

FN313 See 26 U.S.C. §142.

FN314 The Commission also clarified that reciprocal service will not be required if providing such service would jeopardize a G&T cooperative's tax-exempt status.

315 26 U.S.C. §142(f)(2)(A).

316 E.g., NRECA, Oglethorpe, AEC & SMEPA, TANC.

FN317 E.g., Redding, Tallahassee, TANC, Dairyland.

318 E.g., NRECA, Dairyland, TDU Systems, AEC & SMEPA.

319 NRECA at 29. NRECA specifically lists the following: reliability of electric service; impairment of contracts; ability to cease service; all costs associated with the service must be recovered; retail marketing areas; and prohibitions on retail wheeling and sham wholesale transactions. See also Oglethorpe.

320 E.g., EEI, Entergy, Montana-Dakota Utilities, Southwestern, Oklahoma E&G, Southern.

FN321 See also Oklahoma E&G.

322 E.g., Montana-Dakota Utilities, Southern, EEI.

323 FERC Stats. & Regs. at 31,762; mimeo at 374.

324 As discussed infra, non-public utilities may seek a waiver of the reciprocity condition. We therefore reject Tallahassee's argument that we are excluding an entire class of transmission customer from open access, i.e., those unable to grant reciprocal service. If the Commission determines that a particular customer truly is not able to reciprocate, the reciprocity condition can be waived. These situations are obviously different from situations involving entities that do not wish to provide reciprocal service.

325 See Public Service Electric & Gas Company, 78 FERC 61,119, slip op. at 4 and n.7 (1997).

326 With regard to the basic substantive protections such as reliability, opportunity to recover costs, and the standards for rates, terms and conditions of transmission service, we see no relative distinctions between sections 211 and 212 and sections 205 and 206 of the FPA.

327 In response to Southern's citation to Morgan City, while this case provides some background as to the relationship between G&T cooperatives and distribution cooperatives, it in no way suggests that the relationship rises to the level of a corporate affiliation

FN328 However, in response to Umatilla Coop, we clarify that to the extent a distribution cooperative purchases power from an affiliated cooperative that is acting as a power marketer, the distribution cooperative will be subject to the reciprocity condition because of the marketing affiliate relationship between the two. Moreover, as we explained in the Final Rule, the reciprocity condition also applies to any entity that owns, controls or operates transmission facilities and that uses a marketer or other intermediary to obtain access. FERC Stats. & Regs. at 31,763; mimeo at 378.

329 FERC Stats. & Regs. at 31,760; mimeo at 370.

FN330 See South Carolina Public Service Authority (Santee Cooper), 75 FERC 61,209 (1996); Central Electric Cooperative, Inc., 77 FERC 61,076 (1996). Of course, the non-public utility can always seek a waiver of the OASIS and standard of conduct requirements. Such a waiver request will be [evaluated under the same criteria applicable to a waiver requests by a public utility. ***12339**

331 In reaching this conclusion, we note that the electric industry currently conducts business using contract path pricing. If we are presented with a regional proposal for flow-based pricing, we will reconsider whether there is a need to expand reciprocity as requested by certain entities.

332 NRECA raises comparable questions with respect to waiver procedures.

FN333 See also TANC.

334 WRTA supports NWRTA in NWRTA's rehearing request.

335 75 FERC at 61,694-95 (citing 18 CFR 381.108).

336 75 FERC at 61,701.

337 Id.

FN338 Because we have not extended the reciprocity condition to rate aspects of a non-public utility's tariff, we would not evaluate any stranded cost recovery mechanism and, as with respect to all terms and conditions of non-jurisdictional tariffs, the Commission is without jurisdiction to enforce such a charge.

339 E.g., Santee Cooper, Omaha Public Power District (filed petition for declaratory order on October 17, 1996, which was docketed as NJ97-2-000), Southern Illinois Power Cooperative (filed petition for declaratory order on October 8, 1996, which was docketed as NJ97-1-000).

340 76 FERC 61,009 at 61,027 (1996).

341 FERC Stats. & Regs. at 31,761; mimeo at 372.

FN342 For the same reason, we deny Tallahassee's request that we clarify the good faith assertion a public utility must make that the non-public utility has not met the reciprocity condition.

343 FERC Stats. & Regs. at 31,689; mimeo at 156.

FN344 FERC Stats. & Regs. at 31,761; mimeo at 373.

345 32-3 Int'l Legal Materials 682 (1993); 19 U.S.C.A. §3301 et seq. (1995 Supp.)(legislation implementing NAFTA).

346 Ontario Hydro at 4-7.

347 Ontario Hydro at 5.

FN348 Ontario Hydro at 5, 3.

349 NAFTA Article 301, citing GATT, 61 Stat. A5, A18-A19 (1947). "Goods" under NAFTA include transmission service. NAFTA, Articles 606, 609.

FN350 Iroquois Gas Transmission System. L.P.. et al.. 53 FERC 61,194 at 61,700-01 (1990), aff'd sub nom. Louisiana Association of Independent Power Producers and Royalty Owners v. FERC, 958 F.2d 1101 (D C. Cir. 1992), quoting United States-Canada Free Trade Agreement Implementation Act of 1988, Report of the Committee on Energy and Commerce, House of Representatives, H.R. Rep. No. 100-816, Part 7, 100th Cong., 2d Sess. at p. 7 (1988). The Free Trade Agreement is a predecessor to NAFTA.

FN351 We have no section 205-206 jurisdiction over non-public United States utilities, just as we have no jurisdiction over foreign entities. Ontario Hydro's claim that the Open Access Rule "makes open access the law of the land for wholesale transmission service within the United States" is wrong; open access is not the law of the land for United States non-public utilities, since we have no section 205-206 jurisdiction over them.

352 United States public utilities, of course, are separately required by Order No. 888 to have on file open access tariffs and thus meet reciprocity through the separate, more stringent open access requirement.

FN353 Ontario Hydro also complains that the reciprocity obligation of domestic non-public utilities is subject to various limitations and waiver provisions. These provisions apply to foreign entities as well.

354 In recent cases involving the mitigation of transmission market power of Canadian utilities that are affiliates of power marketers that seek to sell power at market-based rates in the United States, the Commission has explicitly acknowledged the sovereign authority of Canadian governments over Canadian entities and has said that we will be "amenable to a variety of approaches" for foreign utilities to mitigate [transmission market power. British Columbia Power Exchange Corporation, 78 FERC 61,024 (1997); accord, TransAlta Enterprises Corporation, 75 FERC 61,268 (1996) and Energy Alliance Partnership, 73 FERC 61,019 (1995). ***12342**

355 EEI and Ontario Hydro note that section 6 of the tariff limits the obligation of foreign utilities to provide reciprocal service to "facilities used for transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer. . . ." (EEI

at 14). This is inconsistent with the preamble, which says that the reciprocity provision applies to foreign entities (whose transmission facilities may not be "interstate"). We recognize that the language in section 6 of the pro forma tariff conflicts with the preamble language of the Final Rule. We are modifying section 6 of the tariff accordingly.

356 We do have jurisdiction over many non-public utilities under certain sections of the FPA, e.g., sections 210, 211 and 212.

357 Oxbow Power Marketing, 76 FERC 61,031 at 61,179 (1996), reh'g pending. We did note, however, that the QF would become a public utility to the limited extent it provides transmission service over its line on behalf of others.

358 See Order Clarifying Order Nos. 888 and 889 Compliance Matters, 76 FERC 61,009 at 61.027 (1996).

359 See also Tucson Power.

360 See also SoCal Edison. It asserts that the Commission should require publicly-owned utilities to provide open access on the same terms as other utilities after a short transitional period that provides an opportunity for the IRS and/or Congress to address the interrelationship between open access transmission and tax-exempt financing.

361 We note that on January 10, 1997, the IRS issued final regulations on the definition of private-activity bonds applicable to tax-exempt bonds issued by state and local governments, but reserved section 1.141-7 dealing with output contracts to further consider the issues raised by regulatory changes in the electric power industry. 62 FR 2275 (January 16, 1997).

362 In response to EEI's request that the Commission require a non-public utility to provide copies of, and specifically reference the tax provisions in, the related financing agreements, we note that the level of detail needed to substantiate a non-public utility's claim that providing reciprocal transmission service would jeopardize the tax-exempt status of its financing is likely to depend on the facts of each case. As a result, what will constitute adequate substantiation is properly determined on a case-by-case basis. Additionally, we will reject EEI's request that the Commission require non-public utilities to demonstrate that they are actively pursuing the issue with the IRS. As we explain above, the IRS is currently examining these issues; we in turn will reexamine our policy after the IRS acts to ensure that the reciprocity condition is applied broadly to achieve open access without jeopardizing tax-exempt financing.

363 We will reject Centerior's request that the Commission condition receipt of open access transmission service by non-public utilities upon the elimination or mitigation of tax subsidies. As we stated in Order No. 888, Congress has entrusted the IRS with the responsibility for implementing laws governing tax-exempt financing, and it is not this Commission's purpose to disturb Congress's and the IRS's determinations in that regard.

FN364 In response to CAMU, we note that the Commission has, in effect, deferred—pending IRS action—a non-public utility's reciprocity obligation in cases in which the provision of reciprocal service would jeopardize the tax-exempt status of the non-public utility's financing.

365 Of course if the transmission provider can provide part of the requested service without jeopardizing tax-exempt status, it should offer to provide such service.

366 Pro Forma Open Access Transmission Tariff, Section 5.2(ii).

FN367 We will reject Local Furnishing Utilities' request that the Commission reconsider whether it should insist on the transmission provider's waiver of the issuance of a proposed order under section 212(c). As Order No. 888 indicates, this aspect of the local furnishing provision of the tariff is similar to a provision included in the transmission tariff of San Diego G&E, one of the Local Furnishing Utilities. Waiver of the issuance of a proposed order enables a transmission provider to expeditiously provide service under section 5.2 of the pro forma tariff, thereby ensuring that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime. Although Local Furnishing Utilities now apparently support the issuance of a proposed order on the basis that the negotiations that normally would follow are likely to provide an opportunity to review the costs associated with the loss of tax-exempt status, we believe that any dispute as to costs subsequently can be resolved without causing any delay in the provision of the requested transmission service. For example, the service could be provided at the maximum rate allowed by the Commission, subject to refund.

368 ConEd suggests that this might occur if, for example, the provision by ConEd of transmission service were to cause it to violate the net importer rule and thereby lose the tax exemption for bonds used to finance its local distribution system. Although we clarify above that section 5 of the pro forma tariff would apply to this situation, we note that it is not clear that wheeling required by the Commission would be counted for purposes of determining whether a public utility is a "net importer." In its committee report on the bill that became the Energy Policy Act, the House Ways and Means Committee stated:

The committee believes further that, in applying the IRS ruling position that a local furnishing utility that is interconnected with other utilities (other than for emergency transfers of electricity) must be a net importer of electricity, the determination of whether the utility is a net importer should be made without regard to electricity generated by another party that is wheeled by the utility to a point outside its service area pursuant to a FERC order authorized under the bill.

H.R. Rep. No. 102-474(VI), 102d Cong., 2d Sess. 25 (1992), reprinted in 1992 U.S.C.C.A.N. 2232, 2236.

369 FERC Stats. & Regs. at 31,763; mimeo at 377.

370 NE Public Power District is a public corporation and a political subdivision of the State of Nebraska that generates, transmits and delivers electric energy to wholesale and retail customers throughout the state

FN371 NE Public Power District at 2. NE Public Power District asserts that the Commission failed to respond to this issue as raised by NE Public Power District in its comments.

FN372 Executive Order No. 12875, 3 CFR 699-71 (1994); 58 Fed. Reg. 58,093-094 (1993). The Executive Order provides that, unless required by statute, no Executive department or agency shall promulgate any regulation that creates a mandate upon state, local or tribal governments unless it either: (a) provides the funds necessary to carry out the obligations; or (b) before promulgating the regulation, provides to the Director of the Office of Management and Budget: (1) a description of its consultation with the affected governments; (2) a statement of their concerns and copies of communications it has received from them; and (3) the reasons why it thinks the regulations should issue.

FN373 The Unfunded Mandates Reform Act is Pub. L. No. 104-4, 109 Stat. 48 (1995) (to be codified at 2 U.S.C. §§602, 632, 653, 658, 1501-1504, 1511-1516, 1531-1538, 1551-1556 and 1571).

374 3 CFR at 670; 58 FR 58093 (1993).

FN375 3 CFR at 671; 58 FR at 58094 (1993) (emphasis supplied).

376 90 Stat 50 (to be codified at 2 U.S.C. §658).

377 42 U S.C.A. §7176 (1995) (Department of Energy Organization Act) (P.L. 95-91, 91 Stat. 586) (1977). See also Pub. L. No. 104-13, the Paperwork Reduction Act of 1995 §3502(5), 109 Stat. 165 (1995) (to be codified at 44 U.S.C. §3502(5)), which provides that "the term 'independent regulatory agency' means [among other agencies] * * * the Federal Energy Regulatory Commission."

378 109 Stat. 70 (to be codified at 2 U.S.C. §1555) (emphasis supplied).

379 I.e., those that own, operate or control interstate transmission facilities and do not obtain a waiver from the Commission.

FN380 Dayton Hudson Corp. v. Eldridge, 742 S.W. 2d 482, 485-86 (1987); Kerrigan v. Errett, 256 N.W. 2d 394, 399 (1977); Huey v. King, 415 S.W. 2d 136, 138 (1967), Black's Law Dictionary 505 (6th ed. 1990).

FN381 A state or municipal power authority, such as NE Public Power District, does not have to agree to reciprocity, and the Commission cannot force it to do so. The Commission is not requiring state or municipal power authorities to provide transmission access. If non-public utilities elect not to take advantage of open access services because they don't want to meet the tariff reciprocity provision, they can still seek voluntary, bilateral transmission service from public utilities.

382 FERC Stats. & Regs. at 31,765-66; mimeo at 384-85.

383 Coalition for Economic Competition, EEI, KCPL, Florida Power Corp.

384 See also EEI at 26 (suggesting "except in cases of a finding by a trier of fact of gross negligence or intentional wrongdoing by the Transmission Provider").

385 See Tex-La Electric Cooperative of Texas, Inc., 69 FERC 61,269 (1994) (requiring clarification that force majeure clause in electric transmission agreement does not excuse negligence); Avoca Natural Gas Storage, 68 FERC 61,045 (1994) (requiring modification of force majeure provision to ensure that parties would be liable for negligence or intentional wrongdoing).

386 The Commission notes that in the past it may have accepted agreements containing gross negligence in force majeure and indemnification provisions. Consistent with the Commission's general policy of not abrogating existing contracts, we leave those provisions undisturbed.

387 See, e.g., Pacific Interstate Offshore Company, 62 FERC 61,260 at 62,733-734 (1993) (requiring amendment of indemnification provisions that required indemnification except in cases of "gross negligence").

388 See, e.g., Texas Eastern Transmission Corporation, 62 FERC 61,015 at 61,107 (1993).

389 To date, the Commission has only issued a suspension order in this proceeding.

390 See changes to tariff sections 1.33, 1.34, 13.4, 13.7 and 17.3.

391 FERC Stats. & Regs. at 31,752-53; mimeo at 346-47.

392 FERC Stats. & Regs. at 31,752; mimeo at 346.

393 FERC Stats. & Regs. at 31,753-54; mimeo at 349-50.

394 E.g., NRECA, Blue Ridge, TDU Systems, Cleveland, AEC & SMEPA, Wisconsin Municipals, TAPS.

395 TAPS filed a response opposing these requests for rehearing. (TAPS Response). As we explained above, we will accept the TAPS Response.

396 74 FERC at 61,018.

397 FERC Stats. & Regs. at 31,754; mimeo at 351.

398 FERC Stats. & Regs. at 31,754-55; mimeo at 353.

399 FERC Stats. & Regs. at 31,794; mimeo at 467.

400 E.g., to protect wholesale purchasers—and, by extension, ultimate consumers—from losing service unjustly; to provide the Commission an opportunity to ensure that the termination is just and reasonable. 77 FERC at 61,171.

401 Id.

402 Dairyland filed a supplemental request for rehearing raising similar arguments. (Dairyland Supplement). We will accept this pleading as a motion for reconsideration, not as a request for rehearing, because it was not filed within the 30-day statutory period for rehearing requests. See 16 U.S.C. §8251(a).

403 FERC Stats. & Regs. at 31,700; mimeo at 191.

FN404 FERC Stats. & Regs. at 31,738; mimeo at 304.

405 FERC Stats. & Regs. at 31,700; mimeo at 191.

406 FERC Stats. & Regs. at 31,729-30; mimeo at 277-78.

407 Mimeo at 769.

FN408 FERC Stats. & Regs. at 33,110 and 31,804-05; mimeo at 85 and 497-98.

409 FERC Stats. & Regs. at 31,763; mimeo at 378

410 FERC Stats. & Regs. at 31,763-64; mimeo at 379-80.

411 FERC Stats. & Regs. at 31,764; mimeo at 380-81.

412 FERC Stats. & Regs. at 31,764; mimeo at 381-82.

413 FERC Stats. & Regs. at 31,764-65; mimeo at 382-83.

414 FERC Stats. & Regs. at 31,766; mimeo at 386.

415 FERC Stats. & Regs. at 31,766-67; mimeo at 386-88.

416 FERC Stats. & Regs. at 31,770; mimeo at 397-98. The Commission has applied its approach to regional practices in filings made in compliance with Order No. 888. See, e.g , American Electric Power Service Corporation, et al., 78 FERC 61,070 (1997); Allegheny Power System, Inc , et al., 77 FERC 61,266 (1996); Atlantic City Electric Company, et al., 77 FERC 61,144 (1996).

417 Order On Non-Rate Terms and Conditions, 77 FERC 61,144 (mimeo at 15-16) (1996).

418 FERC Stats. & Regs. at 31,770 n. 514; mimeo at 399 n. 514.

419 E.g., Santa Clara, Redding, TANC.

420 E.g., Florida Power Corp, Utilities For Improved Transition, VEPCO.

421 FERC Stats. & Regs. at 31,770 n. 514; mimeo at 399 n. 514.

422 See Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc , 78 FERC 61,090 (January 31, 1997).

423 On December 27, 1996, the Commission issued an order that found that

During Phase 1, a request for transmission service made after 2:00 p.m. of the day preceding the commencement of such service, will be "made on the OASIS" if it is made directly on the OASIS, or, if it is made by facsimile or telephone and promptly (within one hour) posted on the OASIS by the Transmission Provider.

77 FERC 61,335 (1996).

424 We further note that CCEM's reference to the Commission's Policy Statement Regarding Good Faith Request for Transmission Services does not support its position. As we there stated,

[a] good faith request for transmission service should also contain a specific, technical description of the requested services in sufficient detail to permit the transmitting utility to model the additional services or its transmission system.

FERC Stats. & Regs. 30,975 at 30,863.

425 E.g., Utilities for Improved Transition, Florida Power Corp, VEPCO.

426 FERC Stats. & Regs. at 31,694; mimeo at 172.

427 While firm resources can also go off line, the probability of this happening is less than that for interruptible resources.

428 See also NRECA.

429 FERC Stats. & Regs. at 31,694; mimeo at 172.

430 E.g., Utilities For Improved Transition, Florida Power Corp, VEPCO (asserts that rates for firm point-to-point service should be developed in the same way).

431 FERC Stats. & Regs. at 31,738; mimeo at 304.

FN432 See FERC Stats. & Regs. at 31,768-70; mimeo at 394-99.

433 To the extent a public utility has been granted a waiver of the Order No. 888 tariff filing requirements (or a non-public utility for reciprocity purposes), it need not submit a request for a separate waiver of the requirements of this order on rehearing.

434 FERC Stats. & Regs. at 31,768-70; mimeo at 393-400.

435 FERC Stats. & Regs. at 31,768-69; mimeo at 394-96.

436 As described in the Transmission Pricing Policy Statement, a "conforming" proposal is one that meets the traditional revenue requirement and reflects comparability. FERC Stats. & Regs. 31,005 at 31,141.

FN437 Given the brief comment period on the compliance filings, the Commission required public utilities to serve copies of their compliance filings (via overnight delivery) on: all participants in their current open access rate proceedings (if applicable); all customers that have taken wholesale transmission service from the utility after the date of issuance of the Open Access NOPR; and the state agencies that regulate public utilities in the states of those participants and customers. By order issued July 2, 1996, the Commission extended the comment period from 15 days to 30 days.

438 FERC Stats. & Regs. at 31,769; mimeo at 396-97.

439 The Commission held that Group 2 public utilities must serve a copy of their filings (via overnight delivery) on all customers that have taken wholesale transmission service from them since March 29, 1995 (the date of issuance of the Open Access NOPR) and on the state agencies that regulate public utilities in the states where those customers are located. By order issued July 2, 1996, the Commission extended the comment period from 15 days to 30 days. ***12365**

440 FERC Stats. & Regs. at 31,769-70; mimeo at 397-98.

44 gFERC Stats. & Regs. at 31,770; mimeo at 398-99.

442 FERC Stats. & Regs. at 31,770; mimeo at 399-400

443 FERC Stats. & Regs. at 31,768-69; mimeo at 394-96.

FN444 FERC Stats. & Regs. at 31,665; mimeo at 87-88.

FN445 See also discussion of prior settlements in Section IV.D.1.c. (2) (Energy Imbalance Bandwidth).

446 See IES Utilities, Inc., et al., 78 FERC 61,023 (1997).

447 We do note that most of these concerns have been addressed in our orders dealing with the compliance filings on non-rate terms and conditions. See, e.g., Atlantic City Electric Company, et al., 77 FERC 61,144 (1996); Allegheny Power System, Inc., et al., 77 FERC 61,266 (1996).

FN448 76 FERC 61,009 at 61,026-27 (1996) (July 2 Order).

FN449 We also note that utilities were required in Order No. 888 to explicitly identify any regional practices in their compliance filings.

450 By order issued September 11, 1996, the Commission denied Indianapolis P&L's requested waiver of all the requirements of Order No. 888. On October 8, 1996, Indianapolis P&L sought rehearing of that order and a stay of the requirements of Order No. 888. These pleadings are now pending before the Commission.

451 FERC Stats. & Regs. at 31,780-85; mimeo at 427-42.

452 324 U.S. 515 (1945) (CL&P); 376 U.S. 205 (1964) (Colton).

FN453 The Commission included a detailed legal analysis in Appendix G to Order No. 888 The Commission explained that it was particularly persuaded by the Supreme Court's statement that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. See CL&P, 324 U.S. at 534-35).

454 In order to give such deference, the Commission noted its expectation that state regulators will specifically evaluate the seven indicators and any other relevant facts and make recommendations consistent with the essential elements of the Rule.

455 The Commission noted that such a tariff could be different from the tariff that applies to wholesale customers, but that such tariff would still be filed with the Commission under FPA section 205.

FN456 In applying the principles of the Final Rule to retail transmission tariffs, the Commission emphasized that it clearly cannot order retail wheeling directly to an ultimate consumer. (citing FPA section 212(h)).

457 E.g., NARUC, WI Com, WY Com.

458 See also IA Com (use of a utility's transmission system to serve its own retail customers is a bundled part of the retail sale transaction, which supports a simpler jurisdictional test holding that a movement of power by the last utility in any chain of delivery to a retail customer is a distribution transaction).

459 See also PA Com.

460 88 F.3d 1105, 1152-53 (1996) (United Distribution Companies).

461 Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927).

462 The case law is addressed extensively in Appendix G to the Final Rule and will not be repeated here

FN463 On rehearing, several parties argue that at least one court case, Wisconsin-Michigan Power Co. v. FPC, 197 F.2d 472 (7th Cir. 1952), cert denied, 345 U.S. 934 (1953) explicitly applied the wholesale/retail distinction to distinguish transmission and local distribution services. The Commission discussed this case in detail in Appendix G to the Final Rule, FERC Stats. & Regs. at 31,974-75; mimeo at 22-25. As we stated there, the court's interpretation of the legislative history of the FPA was at odds with both the plain words of the statute as well as the language of the House Report on the FPA (H.R. Rep. No. 1318 at 27). It also did not mention the Senate Report on the FPA, which clearly recognized jurisdiction over all interstate transmission lines, whether or not a sale of energy is carried by those lines (S. Rep. No. 621 at 48). We therefore reject arguments that this single case is in any way dispositive of the issue before us.

464 See FPC v. Southern California Edison Co., 376 U.S. 205 (1964) (Colton case). IN Com makes a similar argument and opposes "federalization" of retail wheeling within a state's boundaries. We reject this argument on the same basis.

465 See also WI Com (criteria do not appropriately reflect the mixed nature of many facilities in systems that are closely integrated and the application of the criteria to the electric system in Wisconsin would supplant state jurisdiction over a large number of facilities whose primary functions are local reliability and retail service).

466 See Colton, 376 U.S. at 210 n.6; CL&P, 324 U.S at 531-36.

467 Pacific Gas and Electric Company, et al., 77 FERC 61,325 at 61,325 (1996).

468 United Distribution Companies, 88 F.3d at 1154-57.

469 See also AK Com (should not create a fictional concept of delivery service—the legal reality is that, under retail competition, state law will establish a customer's right to be served and a generation owner's right to produce power. AK Com asserts that the state can then attach conditions to those rights).

470 MO/KS Coms at 1-13.

471 See Colton and Connecticut Light and Power, supra.

472 Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988) (AGD).

473 United Distribution Companies v. FERC, 88 F.3d 1105 (1996) (United Distribution Companies).

474 Such access may be the open access required under this Rule or case-by-case transmission access ordered pursuant to FPA section 211.
FN475 We note that the regulations implementing this Rule use "wholesale stranded cost" and "retail stranded cost" as shorthand terms to refer to the different situations in which a utility may experience stranded costs. However, as the definitions of those terms make clear, it is not the nature of the costs (wholesale vs. retail) that is controlling for purposes of stranded cost recovery under this Rule. Rather, the controlling factors are the status of the customer (wholesale transmission services customer vs. retail transmission services customer) with whom the costs are associated, and whether the transmission tariffs used by the customer to escape its former power supplier (thus causing the stranding of costs to occur) were required by this Commission or by a state commission. As a result, "retail stranded costs" refers to stranded costs associated with retail wheeling customers.

476 We reaffirm below our basic determinations, but make certain clarifications on limited issues and grant rehearing on the municipal annexation issue.
FN477 As we explain below, by "Commission-required transmission access" we mean the open access transmission required under this Rule or required pursuant to a section 211 order, as well as transmission provided prior to Order No. 888 (and not pursuant to a section 211 order) where such transmission was provided on a case-by-case basis to comply with the Commission's comparability requirement. See note 484 infra.

478 We have made a minor revision to the regulatory text, section 35.26(c)(2), to conform the language of that section with sections 35.26(b)(1) and (5). A conforming revision has been made to section 35.26(d)(2)(i).

479 In Order No. 888 and here, we sometimes use the shorthand expression "retail-turned-wholesale" customer. By this we do not mean that a retail customer who is an ultimate consumer ceases to be an ultimate consumer, or that this customer begins to purchase electric energy for resale. Rather, in a "retail-turned-wholesale customer" situation, such as the creation of a municipal utility system, a newly-created entity becomes a wholesale power purchaser on behalf of retail customers who were formerly bundled customers of the historical local utility power supplier. The new municipal utility is the conduit by which retail customers, if they cannot obtain direct retail access, can reach power suppliers other than their historical local utility power supplier. Although the retail customers remain bundled retail customers, in that they become the bundled customers of the new entity, we call this a "retail-turned-wholesale customer" situation because the new entity in effect "stands in the shoes" of the retail customers for purposes of obtaining wholesale transmission access and new power supply.
FN480 Exceptions would be self-generation or construction by the new entity of its own transmission line, in which case, as noted earlier, the stranded cost provisions of Order No. 888 would not apply because such options have always been available as alternatives to purchasing power from the historical supplying utility and do not involve the use of the utility's transmission facilities under an open access tariff. Thus the departure of customers under these circumstances cannot be linked to the open access requirements of this Rule.
FN481 As discussed in greater detail in Sections IV.J.6 and IV.J.12 below, we clarify that the opportunity for recovery of stranded costs in a retail-turned-wholesale situation is limited to cases in which the former bundled retail customer subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of its former supplier. We have revised section 35.26(b)(1)(i) of the Commission's regulations accordingly.

482 Unbundled retail transmission services required by a state commission could be taken under the same pro forma open access tariff used by wholesale customers or, if determined appropriate by the Commission, under a separate retail tariff filed at the Commission. The critical point, however, is that in either case, the unbundled services are required by the state and not by this Commission.

483 FERC Stats & Regs. at 31,788-91; mimeo at 451-58.

484 In Order No. 888, we explained that by "new open access" or "open access transmission" we were referring to Commission-jurisdictional open access tariffs or to a tariff ordered pursuant to FPA section 211. Although we generally refer in the text of Order No. 888 and the text of this order to the open access tariffs required under this Rule and to tariffs required pursuant to a section 211 order, we clarify that the "new open access" or "open access transmission" described in this Rule also includes transmission provided prior to Order No. 888 (and not pursuant to a section 211 order) where such tariff filings were made on a case-by-case basis to comply with the Commission's comparability requirement. To avoid any confusion on this point, we refer in this order to all such open access transmission as "Commission-mandated transmission access" or "Commission-required transmission access."

485 E.g., American Forest & Paper, Blue Ridge, TDU Systems, IN Consumer Counselor, IN Consumers, IL Com.

486 IN Consumer Counselor at 9 (citing Order No. 888, mimeo at 452-53); IN Consumers at 10 (same).

487 E.g., APPA, IN Consumer Counselor, IN Consumers, Suffolk County, TDU Systems, Specialty Steel, Occidental Chemical, Central Illinois Light, American Forest & Paper, Nucor, Blue Ridge.

FN488 E.g., APPA, IN Consumer Counselor, IN Consumers, Suffolk County, TDU Systems, Specialty Steel.

489 E.g., American Forest & Paper, Nucor, Blue Ridge.

490 E.g., ELCON, TDU Systems, Central Illinois Light, American Forest & Paper

491 See also American Forest & Paper (unless a utility agrees not to seek stranded costs under the Rule, the utility should not be found to have mitigated its transmission market power for purposes of charging market-based rates, merging with other utilities or otherwise, simply by filing an open access tariff).

492 AGD, 824 F.2d at 1021.

FN493 United Distribution Companies, 88 F.3d 1105 (1996). Although the court remanded that aspect of Order No. 636 that allows pipelines to recover 100 percent of their gas supply realignment costs without requiring any pipeline absorption, we explain in Section IV.J.3 below how Order No. 888 is fully consistent with that remand.

494 See FERC Stats. & Regs. at 31,789; mimeo at 453-54.

FN495 As we explain above, Commission-mandated transmission tariffs is meant to include all open access tariffs filed pursuant to Commission order, including tariffs filed under this Rule, tariffs ordered pursuant to FPA section 211, and tariffs that were filed on a case-by-case basis to comply with the Commission's comparability requirement.

FN496 As a result of the Open Access Rule, 47 Group 2 public utilities, which had no open access transmission tariff available prior to Order No. 888, submitted and had available on July 9, 1996 non-discriminatory open access transmission tariffs. In addition, 101 Group 1 public utilities, which had some version of open access available prior to Order No. 888, filed new open access tariffs effective July 9, 1996 in order to conform to the terms and conditions of non-discriminatory open access service specified in the pro forma tariff. Thus, as of July 9, 1996, 148 of the 166 public utilities had filed Order No. 888 open access tariffs. At least ten others filed open access tariffs after July 9, 1996 (e.g., after the Commission dealt with their waiver requests). This, in the Commission's view, represents an unprecedented acceleration of the transition to competitive bulk power markets. From the issuance of the Open Access NOPR in March 1995 until the effective date of Order No. 888 on July 9, 1996 is only a little more than one year.

497 NASUCA and other petitioners offer no persuasive evidence that meaningful competition took root prior to the availability of the new transmission access requirements. The few utilities that did provide transmission service under open access tariffs prior to the announcement of the Commission's comparability requirement did not offer third parties comparable service. To the contrary, such tariffs contained numerous disparities in the transmission service that the utilities provided to third parties in comparison to their own uses of the transmission system. See, e.g., Entergy Services, Inc., 58 FERC 61,234, order on reh'g, 60 FERC 61,168 (1992), remanded, sub nom., Cajun Electric Power Cooperative, Inc. v. FERC, 28 F.3d 173, 179-80 (D.C. Cir. 1994) (tariff contained limitations on point-to-point service and did not provide network service; tariff reserved transmission provider's right to cancel service in certain instances, even where a customer had paid for transmission system modifications). While the desire of customers for competitive power markets may have preceded Commission-mandated open access, customers had no assurance they could reach alternative suppliers until the Commission required utilities to provide transmission service on a comparable basis.

498 The Rule requires that the utility notify the Commission of the date of termination for this class of contracts within 30 days after the termination takes place. The Rule retains the prior notice of cancellation or termination requirement for power sales contracts executed on or after July 9, 1996 if termination is on grounds other than expiration of the contract by its terms at the end of the contract. See Portland General Electric Company, 75 FERC 61,310, reh'g denied 77 FERC 61,171 (1996) (Commission authorization required for termination of power sales contract in the event of the commencement of a bankruptcy proceeding, failure to perform any obligation under the contract, or failure to provide adequate assurance of the ability to perform).

499 To the extent there is any misunderstanding, we clarify that the intent of the Rule to permit the "opportunity" to recover stranded costs is not an "entitlement" to recover such costs. As a result, the passage in Order No. 888 to which IN Consumer Counselor and IN Consumers object (FERC Stats. & Regs. at 31,789, mimeo at 452-53) should read "we believe that the utility is entitled to an opportunity to recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer" (emphasis to show added language).

500 FERC Stats. & Regs. at 31,794; mimeo at 468-69.

501 As we indicate in Section IV.J.9 below, we disagree that the Rule's definition of stranded costs artificially and unjustifiably improves the competitive position of an inefficient utility.

502 As the AGD court noted: "Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall." 824 F.2d at 1008.

503 As we noted in Order No. 888, there is no question that it is within the Commission's discretion to decide whether to act through rule or through case-by-case adjudication. FERC Stats. & Regs. at 31,679; mimeo at 127-28.

FN504 See AGD, 824 F.2d at 1008.

FN505 Indeed, we are somewhat puzzled by the argument that we may not act in the absence of "hard data" that the potential stranded cost problem is widespread and huge. Here we provide only the opportunity to seek stranded cost recovery for a concededly narrow subset of cases that we believe may give rise to a valid claim for extracontractual recovery. If as petitioners suggest the problem is modest and confined to a small number of utilities, the evidentiary process will sort that out, and the potential effect on departing customers and on the pace of competition will be similarly modest.

506 In making this determination we do not decide whether such situations demonstrate the presence or lack of a reasonable expectation of continuing to serve a customer after the expiration of an existing wholesale requirements contract (i.e., one that was executed on or before July 11, 1994).

FN507 San Francisco will have sufficient opportunity to raise the argument in any PG&E stranded cost recovery case.

508 E.g., EEI, Coalition for Economic Competition, Puget, Centerior, Southern. The issue of expanding the rule to encompass municipal annexations and expansions is discussed in greater detail in section IV.J.6 below.

509 Puget submits that the potential for customers not taking unbundled transmission services from their former suppliers is particularly acute in the Pacific Northwest due to BPA's ownership of much of the region's transmission facilities.

510 NIMO contends that the Commission erred by failing to address the extent to which Order No. 888's exceptions to the general policy of full stranded cost recovery (e.g., no recovery for customer use of new transmission provider or municipal annexations) create an opportunity for customers to avoid payment of part or all of their share of utility stranded costs, will enable customers to take advantage of such opportunities in ways that will reduce rather than enhance overall economic efficiency, and will deprive utilities of a reasonable opportunity to recover their prudently incurred costs or will shift costs unfairly among customers. See also Puget.

511 E.g., Puget, Coalition for Economic Competition, NIMO. These parties make a similar argument in the case of stranded costs that result from retail wheeling. See section IV.J.7 below.

FN512 Puget cites in support Stone v. Farmers' Loan & Trust Company, 116 U.S. 307, 331 (1886); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 602 (1944); and Duquesne Light Company v. Barasch, 488 U.S 299, 307-08 (1989). Puget objects that the stranded cost recovery mechanism in Order No. 888 is too narrow and too easy to circumvent; it can be denied for failure to satisfy the reasonable expectation test or based on a finding that costs are not legitimate and verifiable. Puget argues that stranded cost recovery is constitutionally required and that the recovery mechanism must be amended to ensure full recovery of prudently incurred stranded costs, including PURPA contract costs.

513 E.g., EEI, Oklahoma G&E, Nuclear Energy Institute, Southern. Southern requests that the Commission add a section 35.29 to the regulatory text providing: "Sections 35.26 and 35.28 of this part constitute unseverable portions of a unitary action of the Commission."

514 E.g., Carolina P&L, PSE&G.

515 We discuss in Section IV.J.6 below our disposition of the rehearing requests that support recovery of costs stranded as a result of municipal annexation or expansion. In response to EEI's argument that the Rule would deny recovery for costs stranded pursuant to a voluntarily-negotiated transmission service agreement and would discourage parties from settling transmission disputes, we find EEI's arguments in support of its position to be vague and cursory. However, we do not interpret the Rule in any way as precluding parties from addressing stranded cost issues through settlement, including settlement of a transmission dispute. To the contrary, we fully expect that the renegotiation of contracts, including transmission agreements, would provide parties with a useful means for resolving stranded cost issues without litigation. We believe that a negotiated rate that includes an amount for stranded cost recovery could be found to be just and reasonable.

516 FERC Stats. & Regs. at 31,849-50; mimeo at 624-26.

517 488 U.S. at 307.

518 These parties appear to refer to a situation in which a customer is able to modify or terminate its contract, but would use the transmission system of a utility other than that of its former supplier in order to reach a new generation supplier. In this circumstance, the Rule would not permit the former supplier to seek stranded costs.

519 FERC Stats. & Regs. at 31,789-90; mimeo at 454-55.

520 In addition, the proposal would not eliminate lengthy litigation. It would only change the burden of proof in whatever litigation occurs. FN521 We note, however, that in a section 206 proceeding brought by a customer seeking to shorten or terminate a contract, the customer has the burden (as it would in any section 206 case that it initiates) of presenting sufficient evidence that the contract is no longer just and reasonable. As we stated in the Rule, the utility must present any stranded cost claim at that time. See FERC Stats. & Regs. at 31,664, 31,813; mimeo at 86-87, 521-22.

522 E.g., NRECA, TDU Systems, Dairyland Coop.

523 Stranded costs could also conceivably arise as a result of an ordered interconnection under section 210. However, the rates for such an interconnection would be established pursuant to section 212 and could therefore also include stranded costs.

524 FERC Stats. & Regs. at 31,791; mimeo at 458. If such a transmitting utility seeks stranded cost recovery in a proceeding under sections 211 and 212, it would, consistent with the provisions of the Rule, be limited to recovery associated with requirements contracts executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision.

525 FERC Stats. & Regs. at 31,691; mimeo at 162.

FN526 FERC Stats. & Regs. at 31,760-62; mimeo at 370-74.

527 Although the Commission would not determine the rate, including the stranded cost component of the rate, of a non-public utility, we would review a public utility's claim that it is entitled to deny service to a non-public utility because the stranded cost component of the non-public utility's transmission rate is being applied in a way that violates the principle of comparability.

FN528 We note that in the case of stranded cost claims presented to the Commission by BPA or one of the other PMAs, our review would be limited to that set forth in the applicable statutes and any relevant delegation of authority from the Secretary of Energy. See, e.g., Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §839-839h (1985) (Northwest Power Act), Department of Energy Delegation Order No. 0204-108, as amended, 48 FR 55,664 (1983), amended, 51 FR 19,744 (1986), amended, 56 FR 41,835 (1991), amended, 58 FR 59,716 (1993) (delegation order relating to Western Area Power Administration).

529 FERC Stats. & Regs. at 31,790; mimeo at 456-57.

FN530 FERC Stats. & Regs. at 31,790; mimeo at 456-57.

531 Unless these entities own some transmission used in interstate commerce or are engaged in sales for resale, and are not otherwise exempt under FPA section 201(f), they would not be public utilities under sections 205 and 206. Most transmission dependent utilities are not public utilities.

532 A G&T cooperative that is a transmitting utility could seek recovery of stranded costs if it is ordered to provide transmission services that permit its distribution cooperative to reach another supplier and if it had a requirements contract with the distribution cooperative that was executed on or before July 11, 1994.

533 FERC Stats. & Regs. at 31,763; mimeo at 377-78.

534 Maryland People's Counsel v. FERC, 761 F.2d 780 (D.C. Cir. 1985) (Maryland People's Counsel I). See also Maryland People's Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985) (Maryland People's Counsel II).

535 FERC Stats. & Regs. at 31,790-91; mimeo at 457-58.

536 We clarify, however, that a contract may meet our definition of wholesale requirements contract even though it does not carry the label "requirements contract." The definition refers to a contract that provides any portion of a customer's bundled wholesale power requirements. As discussed above, whether or not a contract meets this definition hinges upon whether the customer depended upon the wholesale supplier for all or part of its power because it could not obtain transmission access to reach other suppliers, i.e., it was captive to the historical local supplier.

537 See 761 F.2d 768.

FN538 See 761 F.2d at 781-82.

539 Pro Forma Open Access Transmission Tariff, section 1 11.

540 TX Com's request for rehearing was filed out-of-time on May 29, 1996 with a request that the Commission accept the rehearing request for filing as of May 24, 1996. TX Com explains it had made arrangements with a courier company to pick up its rehearing request on May 23, 1996 and deliver and file the rehearing request with the Commission before 5 p.m. on May 24, 1996. TX Com states that the courier company failed to pick up the rehearing request on May 23 as previously arranged. TX Com says that when it became aware on May 24 that its rehearing request was not enroute to the Commission, it faxed a copy of the rehearing request to a copier and delivery service in Washington, D.C. The pleading, which was not signed, was delivered to the Commission prior to 5 p.m. on May 24. TX Com states that Commission personnel rejected the filing apparently because it was not signed. TX Com asks that the Commission find good cause under Rule 2001 of the Commission's Rules of Practice and Procedures, 18 CFR 385.2001

(1996), to accept its rehearing request for filing as of May 24, 1996. Under the circumstances, we will accept the rehearing request for filing as of May 24, 1996.

FN541 Texas Utilities Electric Company filed on June 21, 1996 a motion for leave to file and response to TX Com's rehearing request. Texas Utilities opposes TX Com's positions on rehearing. While answers to requests for rehearing generally are not permitted, 18 CFR 385.213(a)(2) (1996), we will depart from our general rule because of the significant nature of this proceeding and will accept Texas Utilities' response.

FN542 "Wholesale stranded cost" is defined as "any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: (1) a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or (ii) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility." Order No. 888, mimeo at 768.

FN543 "Wholesale transmission services" is defined as "ha[ving] the same meaning as provided in section 3(24) of the Federal Power Act (FPA): the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce." Order No. 888, mimeo at 768.

544 76 FERC 61,138 (1996).

FN545 Section 212(k), added by EPAct, provides as follows: (1) RATES.—Any order under section 211 requiring provision of transmission services in whole or in part within ERCOT shall provide that any ERCOT utility which is not a public utility and the transmission facilities of which are actually used for such transmission service is entitled to receive compensation based, insofar as practicable and consistent with subsection (a), on the transmission ratemaking methodology of the Public Utility Commission of Texas. 16 U.S.C. §824k(k) (1994).

546 To clarify that the Order No. 888 stranded cost provisions apply to the intrastate utilities within ERCOT, solely in the context of a section 211 proceeding, we will revise the definition of "wholesale transmission services" in section 35.26(b)(3) to read: "Wholesale transmission services means the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce or ordered pursuant to section 211 of the Federal Power Act (FPA)."

547 28 F.3d 173 (D.C. Cir. 1994) (Cajun).

548 FERC Stats. & Regs. at 31,793-95; mimeo at 464-70.

549 See, e.g., ELCON, Suffolk County, Central Illinois Light, American Forest & Paper, TDU Systems, Blue Ridge, Nucor, IN Consumer Counselor, IN Consumers, APPA, PA Munis, VT DPS, Valero.

FN550 E.g., Central Illinois Light, American Forest & Paper.

FN551 E.g., American Forest & Paper, PA Munis.

FN552 E.g., American Forest & Paper, Occidental Chemical, PA Munis.

553 E.g., Arkansas Cities, IN Consumer Counselor, IN Consumers, Occidental Chemical, PA Munis.

554 E.g., APPA, Arkansas Cities.

555 72 F.3d 147 (D.C. Cir. 1995) (Western Resources).

556 The Commission's power under the FPA carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate operations pursuant to sections 202 and 203, and under like directives contained in sections 205, 206, and 207. Gulf States Utilities Company v. FPC, 411 U.S. 747 (1973). While the Commission lacks principal responsibility for implementing antitrust policy, it retains an obligation to give reasoned consideration to the bearing of antitrust policy on matters within its jurisdiction. Alabama Power Company, et al. v. FPC, 511 F.2d 383 (D.C. Cir. 1974).

557 In contrast to the situation in Order No. 888, the Cajun court did not have before it a generic, Commission-imposed recovery mechanism for distinguishing stranded costs associated with the Commission's ordering of industry-wide open access from all uneconomic costs.

FN558 See AGD, 824 F.2d at 1021.

559 Cf. Eastman Kodak Company v. Image Technical Services, Inc., 504 U.S. at 486-87 (Scalia, J. dissenting) ("Per se rules of antitrust illegality are reserved for those situations where logic and experience show that the risk of injury to competition from the defendant's behavior is so pronounced that it is needless and wasteful to conduct the usual judicial inquiry into the balance between the behavior's procompetitive benefits and its anticompetitive costs.").

560 In effect, we recognize that we may have to endure some short-term delay in the transition from monopoly suppliers to competitive suppliers. However, this is not anticompetitive; it is a necessary part of a scheme that is procompetitive overall. See American Gas Association v. FERC, 888 F.2d 136, 149 (D.C. Cir. 1989) ("If conditioning access is a necessary part of a scheme that is procompetitive overall, however, then it does not violate the NGPA [Natural Gas Policy Act] even if it may seem to be anticompetitive when viewed in isolation.").

561 Eastman Kodak Company v. Image Technical Services, 504 U.S. 451, 461 (1992).

562 A "service" can constitute a "product" for purposes of a tying analysis. See Eastman Kodak Company v. Image Technical Services, Inc., 504 U.S at 462.

FN563 The Rule requires all transmission customers to purchase at least some reactive supply and voltage control service from the transmission provider. However, the Commission found that the cost of such services is "part of the cost of basic transmission service." FERC Stats. & Regs. at 31,706; mimeo at 209. That is, it is a necessary part of providing the service and thus, by definition, not a "tying."

564 Such tariff is a condition, but not the sole condition, for market-based rates. See, e.g., Delmarva Power & Light Company, et al., 76 FERC 61,331 (1996); accord Southern Company Services, Inc., 71 FERC 61,392 at 62,536 (1995); Heartland Energy Services, Inc., et al., 68 FERC 61,223 at 62,059-60 (1994).

FN565 A seller requesting market-based rates is not required to to demonstrate any lack of generation market power with respect to sales from capacity for which construction commenced on or after the effective date (July 9, 1996) of the Rule. 18 CFR 35.27(a). However, if specific evidence is presented by an intervenor that a seller requesting market-based rates for sales from new generating capacity nevertheless has generation dominance, the Commission will evaluate whether the seller has generation dominance with respect to the new capacity. FERC Stats. & Regs. at 31,657; mimeo at 65-66.

566 See FERC Stats. & Regs at 31,797-800; mimeo at 477-85.

FN567 Under the revenues lost approach, a customer's stranded cost obligation is calculated by subtracting the competitive market value of the power the customer would have purchased (on an average annual basis) from the average annual revenues that the customer would have paid had it remained on the utility's generation system, and multiplying the result by the period of time the utility reasonably could have expected to serve the customer beyond the contract termination but for the open access required under Order No. 888. See FERC Stats. & Regs. at 31,839-45 for a detailed explanation of the various components of the formula.

FN568FERC Stats. & Regs. at 31,841; mimeo at }600-01.

569 FERC Stats. & Regs. at 31,793; mimeo at }464-65.

FN570 88 F.3d at 1129, 1182-83.

571 We defined "exit fee" as the charge that will be payable by a departing generation customer upon the termination of its requirements contract with a utility (if the utility is able to demonstrate that it reasonably expected to continue serving the customer beyond the term of the contract), whether payable in a lump-sum payment or an amortization of a lump-sum payment. (The same charge also can be paid as a surcharge on the customer's transmission rate.)

FN572 FERC Stats. & Regs. at 31,797-800; mimeo at 477-85.

573 FERC Stats. & Regs. at 31,800-802; mimeo at 485-90.

FN574 FERC Stats. & Regs. at 31,802-03; mimeo at 490-92.

575 .g., ELCON, IL Industrials, San Francisco, Nucor. Other entities that urge the Commission to require shareholders to shoulder a portion of the utility's stranded costs include Central Illinois Light, AR Com, American Forest & Paper, Nucor, and Occidental Chemical. American Forest & Paper and Nucor suggest that full recovery destroys incentives to mitigate. Several entities also support spreading the costs to all of the utility's customers. E.g., American Forest & Paper, Central Illinois Light, AR Com.

576 IL Industrials at 4-6 (citing Order No. 888, mimeo at 491-92).

577 ERC Stats. & Regs. at 31,802; mimeo at 490.

FN578 NASUCA cites in support of its position Covington & Lexington Turnpike Road Company v. Sandford, 164 U S. 578 (1896); Market Street Railway Company v. Railroad Commission, 324 U S. 548 (1945) (Market Street); Duquesne Light Company v. Barasch, 488 U.S. 299, 315-16 (1989).

FN579 NASUCA cites in support of its position New England Power Company, 8 FERC 61,054 (1979), aff'd sub nom. NEPCO Municipal Rate Committee v. FERC, 668 F.2d 1327 (D.C. Cir. 1981), cert. denied, 457 U.S. 1117 (1982). NASUCA states that in that case, prudently incurred plant investment was abandoned because changing circumstances rendered the investment uneconomic; the Commission provided for a ten-year amortization of the plant investment, with no return on the unamortized balance. NASUCA says that this precedent demonstrates that the "regulatory compact" does not require full cost recovery

580 E.g., Central Illinois Light, Occidental Chemical.

FN581 FERC Stats. & Regs. at 31,802; mimeo at 491.

582 Occidental Chemical argues that requiring gas customers to choose their suppliers during an open season enabled the pipelines to place a dollar value on their take-or-pay obligations. Shippers thus knew at the outset what their gas supply realignment (GSR) surcharge would be and could negotiate with other suppliers accordingly. Occidental Chemical says that most pipelines have already recouped their GSR costs and have made the transition to a competitive supply market in under three years. It argues that, on the other hand, allowing electric stranded costs to be recovered over an indefinite period will blunt the pro-competitive effect of Order No. 888.

FN583 Central Illinois Light supports a recovery mechanism that would allow utilities to allocate stranded costs to requirements customers on a demand basis and to all transmission customers on a commodity basis. It argues that this would recognize the greater cost responsibility of requirements customers, recognize the benefits obtained by all transmission customers from open access, and reduce the charges to all customers to a more reasonable level.

584 We will accept this pleading as a motion for reconsideration, not as a request for rehearing, because it was not filed within the 30-day statutory period for rehearing requests. See 16 U.S.C. §825*l*(a).

585 FERC Stats. & Regs. at 31,802; mimeo at 490-91.

FN586 In response to ELCON's argument that it is not clear how departing wholesale customers who signed contracts in 1985 could have "caused" utilities to incur uneconomic assets such as expensive nuclear facilities that were planned and ordered in the 1970s, we note that customers taking requirements service generally pay an allocated share of total embedded costs, including the cost of investments made before the customer began service. This pricing principle is consistent with the method that Order No. 888 adopts for calculating a departing customer's stranded cost obligation. The revenues lost approach is not an asset-by-asset approach. Instead, it is an approach that looks at a utility's current rates, which are based on all the utility's assets, which may include both high cost and low cost generating facilities of various ages, and relies on the presumption that the fixed costs allocated to departing customers under their current rates are properly assignable to them. Thus, if a utility is able to demonstrate that it had a reasonable expectation of continuing to serve the customer after the contract term, the customer's stranded cost obligation would be computed based on the average annual revenues that the customer would have paid had it remained a customer of the utility; the calculation of stranded costs would not be tied to any particular investments that the utility made in a particular unit. As we explain in Section IV.J.9 below, the use of present annual revenues as the basis for the stranded cost calculation is based, among other things, on the presumption that present rates include all just and reasonable costs of providing service.

587 FERC Stats. & Regs. at 31,850; mimeo at 626.

588 Whether poor management decisions or other actions are imprudent would be decided on a case-by-case basis. See, e.g., New England Power Company, Opinion No. 231, 31 FERC 61,047 at 61,081-84, reh'g denied, Opinion No. 231-A, 32 FERC 61,112 (1985), aff'd sub nom , Violet v FERC, 800 F.2d 280 (1st Cir. 1986); Minnesota Power & Light Company, Opinion No. 86, 11 FERC 61,312 at 61,644-45, order on reh'g, 12 FERC 61,264 (1980). However, a utility's costs are presumed prudent and a person challenging such costs would have the burden of going forward with evidence that raises a serious doubt as to prudence. Id., 11 FERC at 61,645.

589 See, e.g., Maryland v. Louisiana, 451 U.S. 725, 748 (1981); Office of Consumers' Counsel v. FERC, 914 F.2d 290, 292 (D.C. Cir. 1990); City of New Orleans, Louisiana v. FERC, 67 F.3d 947, 954 (1st Cir. 1995).

FN590 See New England Power Company, Opinion No. 295, 42 FERC 61,016, reh'g denied in part and granted in part, Opinion No. 295-A, 43 FERC 61,285 (1988). We note that the Supreme Court case on which NASUCA relies to support its argument that there is no constitutionally guaranteed right of recovery of all prudent investment, Duquesne, also involved electrical generating facilities that were planned but never built. See 488 U.S. 299 (1989).

FN591 See Yankee Atomic Electric Company, Opinion No. 390, 67 FERC 61,318, (Yankee Atomic), reh'g denied, 68 FERC 61,364 (1994), remanded on other grounds, Town of Norwood, Massachusetts v FERC, 80 F.3d 526 (D.C. Cir 1996), offer of settlement accepted, letter dated January 30, 1997, Docket No. ER92-592-005. This case involved a nuclear plant that had been in operation for over 30 years. In affirming the Commission's decision to allow full recovery and not to apply Opinion No. 295's recovery rule for [plants abandoned before operation, the court explained.

Although ratepayers generally `bear the expense of depreciation` and although investors generally 'are entitled to recoup from consumers the full amount of their investment in depreciable assets devoted to public service,' [citations omitted] Opinion No. 295 makes a logical exception to this full recovery rule for plants abandoned before operation; in such cases, ratepayers have not benefitted from the plant. The situation here is quite different. Because customers have benefitted from the operation of the plant for over 30 years, and because ceasing plant operations will benefit customers by lowering rates, such an exception is unwarranted. Moreover, applying Opinion No. 295's recovery rule would not, as it would in the case of a plant that never began operations, promote economic efficiency." 80 F 3d at 532.

In Yankee Atomic, the Commission also allowed recovery of 100 percent of construction work in progress and of post-shutdown O&M expenditures.

592 Order No. 500-H, Regulations Preambles 1986-1990, FERC Stats. & Regs. 30,867 at 31,509 (1989).

FN593 Id. at 31,509-10.

FN594 Id at 31,513.

FN595 Id.

596 Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations, Regulations Preambles 1982-85, FERC Stats. & Regs. 30,637 at 31,301 (1985).

FN597 In Order No. 500-H, the Commission found that, although pipelines incurred total take-or-pay exposure over the period January 1, 1983 through June 30, 1987 of over $24 billion, they made take-or-pay payments totalling only $.7 billion. Order No. 500-H, Regulations Preambles 1986-1990 30,867 at 31,514.

FN598 Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations, Regulations Preambles 1982-85, FERC Stats. & Regs. 30,637 (1985).

599 968 F.2d 1295, 1301 (D.C. Cir. 1992).

FN600 By contrast, Order No. 888 does not provide a presumption of prudence for utilities' stranded cost recovery proposals. Once again, the more traditional concept that the utility must prove costs were prudently incurred will apply.

601 The Court did not review the Order No. 500/528 requirement that pipelines absorb a share of the take-or-pay costs. See AGA v. FERC, 888 F.2d 136, 152 (D.C. Cir. 1989), and AGA v. FERC, 912 F.2d 1496, 1519 (D.C. Cir. 1990), cert. denied, 498 U.S. 1084 (1991), both holding the absorption requirement not ripe for review.

FN602 KN Energy, 968 F.2d at 1301.

FN603 Id. at 1302.

604 FERC Stats. & Regs. at 31,664; mimeo at 84.

605 See, e.g., AGD, 824 F.2d at 1026.

606 United Distribution Companies, 88 F.3d at 1189.

607 Order No. 528-A, 54 FERC 61,095 at 61,303-05 (1991).

FN608 Order No. 500-H, Regulations Preambles 1986-1990, FERC Stats. & Regs. at 31,575. Those orders permitted all pipelines to seek full recovery of their take-or-pay settlement costs through their sales commodity rates. The Commission required pipelines to absorb a share of their Order No. 500/528 take-or-pay costs only if they chose to use the alternative, equitable sharing recovery mechanism.

FN609 Order No. 528-A, 54 FERC at 61,303-05.

610 A number of entities (e.g., VT DPS, Valero, Occidental Chemical) challenge the Commission's suggestion that, after Order No. 436, many of the former bundled sales customers of the pipeline had departed. To the extent that Order No. 888 suggested that many pipelines' sales customers had terminated their sales service before Order No. 636 issued, we note that, as the Commission indicated in Order No. 636, pipeline sales constituted less than 20 percent of total annual throughput on major pipelines. FERC Stats. & Regs. 30,939 at 30,400. However, the Commission also found that in 1991 over 60 percent of peak day capacity on major pipelines that made bundled sales was reserved for pipeline firm sales service. Id. at 30,399. Thus, we clarify that although on an annual basis customers were buying most of their gas from other suppliers, pipelines were making significant sales of gas, particularly on peak days.

611 El Paso Natural Gas Company, 72 FERC 61,083 (1995) (El Paso).

612 FERC Stats. & Regs. at 31,802; mimeo at 489.

613 Transwestern Pipeline Company, 44 FERC 61,164 at 61,536 (1988) (Transwestern).

FN614 El Paso Natural Gas Company, 47 FERC 61,108 at 61,314, reh'g denied, 48 FERC 61,202 (1989).

615 Order No. 500, Regulations Preambles (1986-1990), FERC Stats. & Regs. 30,761 at 30,793-94 (1987).

FN616 CPUC v. FERC, 988 F.2d 154, 168 (D.C. Cir. 1993), quoting, Transwestern Pipeline Company, 55 FERC 61,157 at 61,509 (1991).

FN617 Transwestern, 44 FERC at 61,536. The 1989 El Paso order cited by VT DPS and Valero (47 FERC 61,108) reiterated the policy established in Transwestern concerning exit fees in the context of GICs. The El Paso order is distinguishable from our approach to exit fees in Order No. 888 for the same reasons as Transwestern.

618 Natural Gas Pipe Line Company, 46 FERC 61,335 at 62,013 ("Consistent with the court's holding in AGD, that Part 284 transportation and CD conversion must be accompanied by take-or-pay relief, the Commission finds that a pipeline's sales customers who convert to transportation must continue to be liable for the take-or-pay costs allocated to them without regard to the fact that they are no longer sales customers but only transportation customers."), reh'g denied, 47 FERC 61,247 (1989); Transwestern Pipeline Company, 65 FERC 61,060 at 61,473 (1993), reh'g denied, 66 FERC 61,287 at 61,827-828 (1994), aff'd sub nom. Western Resources, Inc. v. FERC, 72 F.3d 147 (D.C. Cir. 1996).

619 Transwestern Pipeline Company, 64 FERC 61,145 at 62,166 (1993), reh'g denied, 66 FERC 61,287 (1994). However, as illustrated by the situation described in the cited Transwestern order, some sales customers had departed altogether from the systems of their historical pipeline suppliers before the Commission recognized the need for continued allocation of Order No. 500 take-or-pay costs to those customers. In these circumstances, the filed rate doctrine prevented such continued allocation.

620 72 FERC 61,083 (1995).

621 In Order Nos. 636-A and 636-B, the Commission not only rejected exit fees where the [customer left the system altogether, but also found exit fees unnecessary for the recovery of GSR costs in the circumstance in which a bundled sales customer converts to transportation-only service. See Order No. 636-B, 61 FERC 61,272 at 62,041 (1992). Exit fees were unnecessary in the latter circumstance because under the Commission's method of allocating GSR costs to all firm transportation customers based on their contract demands, a former bundled sales customer would pay the same GSR costs after terminating its sales service (through the volumetric surcharge on transportation) as it would if it had remained as a sales customer.

FN622 As we explained in Order No. 888, the Commission did not treat a notice of termination provision in El Paso's contract as a conclusive presumption that El Paso had no reasonable expectation of continuing to serve certain customers, as VT DPS and Valero contend. FERC Stats. & Regs. at 31,802, note 639; mimeo at 489, note 639. Instead, the July 1995 El Paso order acknowledged that the April 1995 Supplemental Stranded Cost NOPR had proposed that the existence of a notice of termination provision in a contract be treated as a "rebuttable" presumption of no reasonable expectation. On that basis, the Commission suggested in dicta that "[e]ven if the rules proposed in [the Supplemental Stranded Cost] NOPR were applied here [which they were not], El Paso would have difficulty justifying" its exit fee proposal under the NOPR's reasonable expectation standard given the existence of a notice of termination provision in the contract. 72 FERC at 61,441 (emphasis added).

623 Under their proposal, it appears that costs would be "unrecoverable" only if there were no wholesale load from which to recover the costs. This would result in shifting costs to customers that had no responsibility for causing them to be incurred or for causing them to be stranded. In Order No. 888, we rejected such an approach as fundamentally unfair and as inconsistent with the well-established principle of cost causation.

624 In support of this argument, they cite CPUC v. FERC, 894 F.2d 1372, 1380-81 (D.C. Cir. 1990) as standing for the proposition that, in a cost-based transmission rate, there is no logical basis for including gas-supply related expenses or savings in the rates for customers who take only transmission service. See also American Forest & Paper (no justification for including excess generation costs in transmission rates).

625 E.g., TX Com, APPA, IN Consumer Counselor, IN Consumers, PA Munis, AR Com, MO/KS Coms.

FN626 E.g., APPA, PA Munis, IN Consumer Counselor, IN Consumers.

627 PA Munis at 28. PA Munis also argues that the last sentence of section 212(a) makes it clear that the "rates, charges * * * for transmission services provided pursuant to an order under section 211 shall ensure that to the extent practicable, costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services are recovered * * *. '" (emphasis added by PA Munis).

FN628 See also IN Consumers, IN Consumer Counselor.

629 PA Munis cites in support the following excerpt from House Report No. 102-474, Part I: This section [211] also provides that FERC shall permit the transmitting utility to recover all prudent costs incurred in connection with providing transmission services, plus a reasonable return on investment, including an appropriate share of the costs of any enlargement of transmission facilities necessary to provide such service. H.R. Rep. No. 102-474, Part I, 102d Cong., 2d Sess. 194 (1992), reprinted in 1992 U.S.C.C.A.N. 1959, 2017 (emphasis supplied by PA Munis). ***12397**

630 They cite in support of this proposition Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir.), cert. denied, Williams Pipe Line Company v. Farmers Union Central Exchange, Inc., 469 U.S. 1034 (1984).

631 88 F.3d at 1188-89.

632 Additionally, we note that a stranded cost surcharge to transmission is merely a vehicle for collecting the exit fee. The surcharge would be in effect only until the stranded cost obligation is met. It is not a component of the transmission rate in the sense that a transmission customer who uses a very large amount of transmission while the rate is in effect would pay more than its stranded cost obligation.

FN633 See Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993) (Penelec). As the Commission explained, opportunity costs are the actual costs that a utility incurs by providing transmission service to a customer instead of using the transmission itself to reduce its generation costs on behalf of its native load (i.e., the foregone economy energy transfers). Pennsylvania Electric Company, 60 FERC 61,034 at 61,120, 61,126 (1992), aff'd, Penelec, 11 F.3d 207.

FN634 Technically, the costs in the latter situation were previously incurred as a result of investment by the utility on behalf of the departing customer. However, the costs are "incurred" in the sense of becoming stranded when the customer leaves the utility's system. In both situations, recovery of the costs is permitted through transmission rates in order to keep the utility (and its other customers) from unfairly suffering economic losses as a result of providing transmission to others.

635 Moreover, we note that, in addressing the natural gas industry's transition costs, the Commission did rely on traditional cost causation principles in approving pipeline proposals to allocate fixed take-or-pay charges to sales customers converting to transportation-only service. See Transwestern Pipeline Company, 65 FERC 61,060 at 61,473 (1993), reh'g denied, 66 FERC 61,287 at 61,825-28 (1994). The Commission found that the pipelines entered into their take-or-pay contracts to serve their sales customers. The conversion of those customers to open access transportation required pipelines to enter into settlements with producers to shed gas supplies. Therefore, there was a causal connection between the customer's conversion and the pipeline's incurrence of the take-or-pay settlement costs. Here, there is a similar causal connection between the stranding of generation investment made on behalf of a wholesale customer and that customer's decision to use Commission-mandated open access transmission to reach a new supplier.

FN636 The case on which VT DPS and Valero rely, CPUC v. FERC, involved the disposition of a pipeline's production-related deferred tax reserve when the switch to NGPA pricing mooted application of tax normalization (which sought to match the timing of a customer's contribution toward a cost with enjoyment of any offsetting tax benefit). The Commission's decision not to credit the deferred tax reserve to current users of the pipeline's transmission service was based, among other things, on a determination that the deferred tax fund was completely unrelated to the pipeline's transmission service. See 894 F.2d at 1378-80. In contrast, as discussed below, the costs for which this Rule provides an opportunity for recovery would not have been stranded but for Commission-mandated transmission access.

FN637 We also reject AR Com's argument that the Farmers Union case prohibits the Commission from allowing the recovery of non-transmission costs in a transmission rate in the limited circumstances proposed in Order No. 888. The issues before the court in that case are distinguishable from the recovery of stranded generation costs in transmission rates. Farmer's Union involved the court's review of a Commission order establishing maximum rate ceilings to be applied to oil pipelines in which the Commission invoked non-cost factors (the need to stimulate additional oil pipeline capacity) as one reason for setting high maximum rates. The use of non-cost factors was itself not at issue. Rather, the court found that the Commission had "failed to specify in any detail how 'non-cost' factors, such as the need to stimulate additional pipeline capacity, might justify its decision to set maximum rates at such high levels." 734 F.2d at 1501. In Order No. 888, in contrast, the Commission has fully explained the basis for giving utilities an opportunity to recover stranded costs from departing customers through a surcharge to the customers' transmission rates.

638 See note 633 supra.

639 See Orange and Rockland Utilities, Inc., 76 FERC 61,037 (1996)

640 FERC Stats. & Regs. at 31,804-06; mimeo at 497-501.

641 FERC Stats. & Regs. at 31,805; mimeo at 497.

642 E.g., TDU Systems, OH Consumers' Counsel. TDU Systems proposes that the Commission give a requirements customer the choice of extending its existing contract at existing rates for a period corresponding to the customer's expectation of continued service or receiving a payment from the utility consisting of the difference between what the customer must pay for new supplies and what it paid under the contract. TDU Systems describes the latter option as a "benefits lost" approach modeled after the "revenues lost" approach of Order No. 888.

FN643 FERC Stats. & Regs. at 31,805; mimeo at 498 (emphasis added by OH Consumers' Counsel).

644 If the customer under a contract has not waived its rights to seek changes to the contract, it may exercise its procedural rights under section 206 to show that failure to extend the contract at the existing contract rate would not be just and reasonable. If the customer has waived its rights to challenge the contract (i.e., it is bound by a Mobile-Sierra standard), it may exercise its rights under section 206 to show that it would be contrary to the public interest not to extend the contract at the existing rate. Although OH Consumers' Counsel objects that a section 206 proceeding is an inadequate remedy because it places the burden of proof on the customer, we believe that it is appropriate that the customer, as the complainant in such a case, bear the burden of proof.

645 FERC Stats. & Regs. at 31,809-814; mimeo at 510-24.

FN646 We explained that if an existing requirements contract includes an explicit provision for payment of stranded costs or an exit fee, we will assume that the parties intended the contract to cover the contingency of the buyer leaving the system, and we will reject a stranded cost amendment to such a contract unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to a new stranded cost provision. Similarly, we said that we will reject a stranded cost amendment to an existing requirements contract if the contract prohibits stranded cost recovery (or precludes recovery for termination or reduction of service) or prohibits renegotiation of an existing stranded cost or exit fee provision, unless the parties to the contract mutually agree to a new stranded cost provision.

647 See United Gas Pipeline Company v. Mobile Gas Service Corporation, 350 U.S. 332 (1956); FPC v. Sierra Pacific Power Company, 350 U.S. 348 (1956).

FN648 As a complement to our finding that, notwithstanding a Mobile-Sierra clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of this Rule, we concluded that customers under Mobile-Sierra contracts ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

649 Citing Motion Picture Association of America v. Oman, 969 F.2d 1154 (1992); Bowen v. Georgetown University Hospital, 488 U.S. 204 (1988).

650 Puget notes that it executed a letter agreement with the Port of Seattle on January 12, 1995 to continue in place the terms of an existing contract until February 2, 1996, or the execution of a new agreement, whichever was earlier. It says that the parties were working within the context of the initial stranded cost NOPR, which would have given Puget three years from the date of the publication of the final rule to negotiate or file for stranded cost recovery. However, based on the definition of "new" contract in the Supplemental NOPR, the extension of the Puget/Port of Seattle contract may have converted it into a "new" rather than an "existing" contract for stranded cost recovery purposes. Puget states that it filed an amendment to the contract on December 28, 1995, that included stranded cost recovery provisions. Those provisions are pending in Docket Nos. ER96-714-000 and ER96-697-000. On January 10, 1997, the presiding judge issued an Initial Decision in Docket No. ER96-714-001 finding that Puget, by executing the January 1995 letter

agreement, had not waived its eligibility to recover stranded costs. See Puget Sound Power & Light Company, 78 FERC 63,001 (1997).

651 As discussed in note 650, supra, the presiding judge in Docket No. ER96-714-001 recently issued an Initial Decision finding that Puget did not waive its eligibility to recover stranded costs when it entered into a January 1995 letter agreement with the Port of Seattle extending the term of the parties' 25-year sales contract for up to one year to accommodate further negotiations. Puget Sound Power & Light Company, 78 FERC 63,001 (1997).

652 See, e.g., ELCON, PA Munis, APPA.

FN653 See also ELCON.

654 824 F.2d at 1019.

655 Northeast Utilities Service Company v. FERC, 55 F.3d 686 (1st Cir. 1995) (Northeast Utilities).

656 See Order No 888, FERC Stats & Regs. at 31,679; mimeo at 127-28.

657 Because the Commission's public interest finding only applies to utilities that would seek to amend their contracts to add stranded cost provisions (not to those that face no stranded cost exposure and thus no need to amend their contracts to add stranded cost provisions), we reject as misplaced PA Munis' claim that there is no protection for customers having Mobile-Sierra contracts with public utilities that are not faced with financial problems or cost shifting to third parties as a result of the open access requirements.

658 As noted above, this finding applies only to wholesale requirements contracts with Mobile-Sierra clauses if the contracts were executed on or before July 11, 1994 and do not contain an exit fee or other explicit stranded cost provision.

659 824 F.2d at 1019.

660 Id. at 1019-20.

661 We note that the fact that a contract may bind a utility to a Mobile-Sierra standard does not mean that the customer is also bound to that standard. Unless a customer specifically waives its section 206 just and reasonable rights, the Commission construes the issue in favor of the customer.

FN662 In situations in which a customer institutes a section 206 proceeding to modify a contract that binds the utility to a Mobile-Sierra standard, the utility may make whatever arguments it wants regarding any of the contract terms, including those unrelated to stranded costs, but will be bound to a Mobile-Sierra standard for contract terms that do not relate to stranded costs.

663 FERC Stats. & Regs. at 31,664, 31,813; mimeo at 86, 521.

664 FERC Stats. & Regs. at 31,814; mimeo at 522-23.

665 APPA at 49. It should be noted that, as the Northeast Utilities court indicated, the Papago court's description of the public interest standard as "practically insurmountable" was dictum. 55 F 3d at 691. Further, Papago did not involve a contractual arrangement for rate revision where the parties "by broad waiver * * * eliminate both the utility's right to make immediately effective rate changes under §205 and the Commission's power to impose changes under §206, except the indefeasible right of the Commission under §206 to replace rates that are contrary to the public interest." Papago, 723 F.2d at 953. Instead, Papago involved a contractual regime that "contractually eliminate[d] the utility's right to make immediately effective rate changes under §205 but [left] unaffected the power of the Commission under §206 to replace not only rates that are contrary to the public interest but also rates that are unjust, unreasonable, or unduly discriminatory or preferential to the detriment of the contracting purchaser." Id. See also id. at 953-54.

FN666 Southern Company Services, Inc., 67 FERC 61,080 at 61,228 (1994); see also Florida Power & Light Company, 67 FERC 61,141 at 61,398-99 (1994).

667 66 FERC 61,332 at 62,081, reh'g denied, 68 FERC 61,041 (1994).

668 66 FERC at 62,081-83; see also Southern, 67 FERC at 61,228-29.

669 E.g., Central Montana EC, Central Illinois Light.

670 It is not possible for the Commission to come up with a reliable yardstick of the remaining terms of existing requirements contracts. The Commission's files do not categorize rate schedules as requirements, coordination and transmission-only contracts. Moreover, there is no uniform format for requirements contracts. Many have evergreen provisions, the terminology of which varies from contract-to-contract (e.g., some may be year-to-year, others may roll over).

FN671 The value of its assets could vary over time as new technologies emerge, fuel costs fluctuate, or environmental requirements change.

672 FERC Stats. & Regs. at 31,818-19; mimeo at 534-37.

FN673 We indicated that we will require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer (and will apply the same procedures for determining stranded cost obligation) as that required in the case of a wholesale requirements customer.

674 E.g., NARUC, TAPS, Nucor, Suffolk County, IL Com, Multiple Intervenors, APPA, CAMU, WI Com, NASUCA.

675 E.g., ELCON, IL Com, IN Com, American Forest & Paper, AR Com, MO/KS Coms, NJ BPU, Suffolk County, WY Com, VA Com, FL Com, NARUC, TAPS.

676 VT DPS and Valero cite in this regard Florida Power & Light Company, 8 FERC 61,121 (1979); Power Authority of the State of New York v. FERC, 743 F.2d 93 (2d Cir. 1984); Metropolitan Transportation Authority v. FERC, 796 F.2d 584 (2d Cir. 1986).

677 American Forest & Paper cites in support of its position Great Lakes Gas Transmission Limited Partnership, 68 FERC 61,376 (1994).

678 United Illuminating Company, 63 FERC 61,212, reh'g denied, 64 FERC 61,087 (1993) (United Illuminating).

FN679 See also Suffolk County Rehearing (Commission's analysis in United Illuminating was correct; nothing has changed to warrant the Commission's rejection of that analysis).

680 In the case of municipalization, the bundled retail customers of a local utility become the bundled retail customers of the new municipal utility. As explained above, we call this a "retail-turned-wholesale customer" situation because the new municipal entity in effect "stands in the shoes" of the retail customers for purposes of obtaining wholesale transmission access and new power supply.

681 In response to VT DPS and Valero, we note that whether or not Otter Tail may have agreed to wheel power for the municipal utility that Elbow Lake planned to create if Otter Tail could have made a stranded cost claim against that municipal utility is of no moment to the Commission's decision in Order No. 888 to allow utilities the opportunity to seek recovery of stranded costs associated with retail-turned-wholesale customers. The Court in Otter Tail did not address the stranded cost issue because it was not presented in that case. Nor was the Court presented with the extraordinary circumstances—the historic statutory and regulatory changes, including the requirement of open access, that have converged to fundamentally change the obligations of utilities and the markets in which they operate—that have justified this Commission's Order No. 888 stranded cost policy.

682 Texas Gas Transmission Corporation, 65 FERC 61,275 (1993).

FN683 Texas Gas Transmission Corporation, 69 FERC 61,245, reh'g, 70 FERC 61,207 (1995) (requiring pipeline to offer LDC a reduction in its contract demand).

FN684 See Southern Natural Gas Company, 75 FERC 61,046 at 61,158 (1996); Arcadian Corporation v. Southern Natural Gas Company, 67 FERC 61,176 at 61,538 (1994). See also United Distribution Companies, 88 F.3d at 1181. As the United Distribution Companies court noted, the Commission has given an LDC relief (and required the bypassing customer to bear its share of transition costs) if the LDC can show a direct nexus between the bypass and the pipeline, although the Commission has declined to adopt a generic rule addressing this issue. 88 F.3d at 1180-81.

685 63 FERC at 62,583-84.

686 E.g., EEI, SoCal Edison, Centerior, Atlantic City, PSE&G, Puget, Public Service Co of CO, Coalition for Economic Competition.

FN687 E.g., EEI, SoCal Edison, PSE&G, Puget, Public Service Co of CO, Coalition for Economic Competition. Coalition for Economic Competition suggests, for example, that villages and large industrial customers may opt to join existing municipal systems that, in most cases, will use Commission-jurisdictional transmission tariffs to obtain resources to supply power to the annexed loads.

688 E.g., EEI, Coalition for Economic Competition, Atlantic City, Puget, Public Service Co of CO.

FN689 74 FERC 61,086, final order directing transmission service, 76 FERC 61,265 (1996).

690 SoCal Edison requests clarification that a transaction in which a retail customer disconnects from a utility's system and accesses another generation supplier by interconnecting with a public power entity, who in turn would interconnect with a neighboring jurisdictional utility, constitutes a municipalization, not an expansion of a service territory. Because we have decided to treat municipal annexations (or expansions) and new municipalizations similarly for purposes of stranded cost recovery under the Rule, SoCal Edison's request is moot to the extent that it envisions a scenario in which the former supplier's transmission system is used to access a new generation supplier. However, as discussed below, the Rule would not provide an opportunity to seek recovery of stranded costs if the municipal entity in the scenario described by SoCal Edison does not use the former supplier's transmission system.

691 FERC Stats. & Regs. at 31,819; mimeo at 536-37

692 FERC Stats. & Regs. at 31,819; mimeo at 537.

693 FERC Stats. & Regs. at 31,824-26; mimeo at 553-58.

FN694 "State regulatory authority" has the same meaning as provided in section 3(21) of the FPA:

'State regulatory authority' has the same meaning as the term 'State commission', except that in the case of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority (as defined in section 3 of the Public Utility Regulatory Policies Act of 1978), such term means the Tennessee Valley Authority.

695 376 U.S. 205, 215-16 (1964).

696 E.g., Central Illinois Light, IN Consumer Counselor, IN Consumers, Nucor, FL Com, WI Com, VA Com, AR Com, MO/KS Com, OH Com, APPA. For example, FL Com asserts that costs for facilities that are currently under the jurisdiction of state authorities do not become the Commission's jurisdiction because retail wheeling is instituted; in most cases, the states approved both the construction and the cost recovery for these facilities under bundled rate structures. FL Com submits that the states are in a better position to judge the extent and value of assets that may become stranded as a result of retail wheeling.

FN697 E.g., APPA, AR Com, MO/KS Coms, OH Com

698 E.g., NARUC, TAPS.

699 E.g., NASUCA, NY Com, WY Com, NARUC. The Consumer's Utility Counsel Division of the Georgia Governor's Office of Consumer Affairs filed comments on June 24, 1996, in support of NARUC's request for rehearing on the jurisdictional issues pertaining to the recovery of retail stranded costs. While answers to requests for rehearing generally are not permitted, 18 CFR 385.213(a)(2) (1996), we will depart from our general rule because of the significant nature of this proceeding and will accept these comments.

FN700 According to NASUCA, whether or not that authority includes a requirement that a utility receive 100 percent return on stranded costs (or something less) is a matter to be determined by the state courts and legislatures.

701 See also AR Com (one retail transaction is replaced by another retail transaction; there is no wholesale transaction and no wholesale costs over which the Commission has jurisdiction).

702 E.g., NARUC, Central Illinois Light, IN Com, American Forest & Paper, IN Consumer Counselor, IN Consumers, IL Com.

703 E.g., Central Illinois Light, IN Com, American Forest & Paper, IN Consumer Counselor, IN Consumers, IL Com. TX Com considers that it has the power to address stranded cost issues related to retail transmission service.

FN704 IL Com at 38 (emphasis in original).

705 E.g., ELCON, NASUCA, IL Com, NY Com.

706 See FERC Stats. & Regs. at 31,780-85; mimeo at 427-42 and Appendix G.

707 If a utility is regulated by both this Commission and a state commission, each commission, in setting cost-of-service rates within its jurisdiction, will separately and independently determine the utility's total cost of providing service (also known as the utility's total revenue requirement). This will be based on the expenses incurred in providing service and a reasonable profit on the utility's assets that are used to provide the service. The commissions may differ as to what assets are appropriately included in total rate base, what other costs are appropriately included in the total cost of service, and what rate of return should be permitted. Once each regulatory authority has determined the appropriate total revenue requirement, it then will determine what portion of that total revenue requirement should be borne by the utility's wholesale customers and what share should be borne by retail customers (also called cost allocation). Each commission may also reach different conclusions on this split as well. Thus, under historical cost-based ratemaking, regulatory authorities do not carve out so-called "wholesale costs" that only this Commission can take into account in determining rates subject to its jurisdiction or so-called "retail costs" that only a state commission can take into account in determining rates subject to state jurisdiction. Additionally, this Commission and state commissions have the discretion to determine whether costs are appropriately recovered through a transmission, generation, or distribution component of a rate (also called functionalization of costs) within their respective jurisdictions.

FN708 We reject arguments that stranded retail generation costs are not a cost of providing unbundled retail transmission. While such costs are not a cost of operating the physical transmission system, nevertheless, they are an economic cost incurred as a result of being required to provide retail transmission. ***12412**

709 This is not a regulatory "gap" in the sense that the Commission would be asserting authority over matters not within its jurisdiction. However, the Commission would be filling a regulatory "gap" to the extent that the utility normally would have the opportunity to seek approval from its state regulatory commission to recover costs in retail rates from a departing retail customer or to reallocate those costs to other retail customers. In circumstances where the utility does not have this opportunity because the state regulatory authority has no authority to address the issue, we may appropriately fill this regulatory "gap" to permit recovery from the departing customer through the retail transmission rate.

710 E.g., Utilities For Improved Transition, Coalition for Economic Competition.

FN711 FERC Stats. & Regs. at 31,784; mimeo at 439.

712 Utilities For Improved Transition argues that, based on Consolidated Edison Company of New York, Inc., 15 FERC 61,174 at 61,405 (1981) and other cases, the Commission has jurisdiction over the entire delivery service (rendered on both the transmission and local distribution facilities) as a transmission transaction. Utilities For Improved Transition submits that states do not have authority over rates on local distribution facilities used to complete a transmission transaction.

713 EEI states that the Commission did not rebut EEI's argument that the Commission's failure to address all retail stranded costs was unduly discriminatory.

714 In support of its argument, Coalition for Economic Competition cites Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 602 (1944); Duquesne Light Company v. Barasch, 488 U.S 299, 307-08 (1989).

FN715 Coalition for Economic Competition at 14.

716 E.g., Centerior, Southern, SoCal Edison.

717 We also explained that the case law they cite (which they refer to again in their rehearing requests) to support the proposition that an agency is not authorized to abdicate its statutory responsibility or to delegate to parties and intervenors regulatory responsibilities is factually distinguishable and inapposite. See FERC Stats. & Regs. at 31,825 and note 765; mimeo at 554-55 and note 765.

FN718 The entities who argue that the Commission has abdicated or delegated its jurisdiction to the states misconstrue the Commission's jurisdiction to determine rates for unbundled transmission in interstate commerce as somehow including exclusive "jurisdiction" over "costs." However, as discussed above, neither this Commission nor the state commissions has exclusive "jurisdiction" over "costs." Rather, each has jurisdiction to determine "rates" for services subject to its jurisdiction. It is in the course of determining "rates" for unbundled transmission in interstate commerce that this Commission can take into account various costs incurred by a utility to provide jurisdictional service. A state commission can take those same costs into account in making its separate and independent determinations of what costs may be recovered through rates within its jurisdiction. See note 707, supra, and accompanying text.

FN719 Based on these same considerations, we reject Coalition for Economic Competition's request that the Commission assume a backstop role for all stranded costs associated with retail wheeling customers but defer to state stranded cost determinations so long as they are consistent with the Commission's policy.

720 If the state regulatory authority is the forum before which to seek recovery, the utility may make whatever arguments it wishes regarding the justness and reasonableness of its rates, as well as any unconstitutional taking arguments it may have, before the state forum. Further, it can pursue appeals of unfavorable decisions through the state court system.

721 We note that the definition of "retail stranded cost" in section 35.26(b)(5) mistakenly refers to "a public utility or transmitting utility" (emphasis added). We will revise the definition to remove the reference to "transmitting utility."

722 See also MO/KS Coms (the cost-shifting problem does not arise because of a particular state treatment of stranded costs; it arises because Entergy insists on recovering 100 percent of its costs even when some portion of the costs are not economical).

FN723 AR Com also objects to the Commission's description of the issue as involving not only holding companies, but also other multi-state situations. AR Com says that "[t]he mere fact that a company's territory crosses state lines does not automatically mean that all assets serve all customers, or that all customers are required to bear the economic risk associated with all assets, or that assets that at one time were solely state-jurisdictional can somehow, by virtue of a company's decision to expand across state lines, become FERC-jurisdictional." AR Com at 11.

724 FERC Stats. & Regs. at 31,831; mimeo at }570-72.

725 FERC Stats. & Regs. at 31,831; mimeo at 572. We indicated that the same procedures would apply to retail customers that obtain retail wheeling.

726 FERC Stats. & Regs. at 31,831; mimeo at }572-73.

727 AMP-Ohio submits that where transmission access and competition have existed to varying extents for decades, there should be an irrebuttable presumption of no reasonable expectation of continued service.

728 E.g., APPA, American Forest & Paper, Central Montana EC, NRECA, TDU Systems, Oglethorpe, IMPA, VT DPS, Valero, PA Munis.

FN729 E.g., APPA, NRECA, TDU Systems. See also VT DPS and Valero (by signing a contract with a termination date, the utility assumed the risk that the customer will elect to leave when the contract expires).

730 In support of its argument, PA Munis cites Boston Edison Company, 56 FPC 3414 (1976). See also American Forest & Paper.

FN731 Citing Kentucky Utilities Company, 23 FERC 61,317 (1983); Philadelphia Electric Company and Susquehanna Electric Company, 65 FERC 61,303 (1993).

732 E.g., NRECA, IMPA, PA Munis.

733 FERC Stats. & Regs. at 31,665, 31,813-14; mimeo at 87, 522.

734 See Kentucky Utilities Company, 23 FERC at 61,679-80 ("Once it receives an effective notice of cancellation, Kentucky can stop planning for the future needs of that customer. . . . To be effective a notice of cancellation must contain a specification of the source of supply, the date on which the source of supply will be available, and an affidavit from the supplier that it will supply the customer on the date the contract ends.").

FN735 See Potomac Electric Power Company, 43 FERC 61,189 (1988) (suspending a notice of termination for five months due to questions about the impact of the proposed cancellation on service reliability).

736 E.g., EEI, Oklahoma G&E, Southern, Florida Power Corp, Utilities For Improved Transition.

737 Briefly, SCO refers to the departing customer's stranded cost obligation, which is determined by taking the average annual revenues that the customer would have paid had it remained a customer of the utility (RSE), and subtracting from it the competitive market value of the power (on an average annual basis) no longer taken by the departing customer (CMVE). The difference represents the average annual stranded cost, which must be multiplied by "L" (L represents the period over which the utility reasonably could have

expected to serve the departing customer beyond the contract termination, but for the open access required under Order No. 888) to produce the departing customer's total SCO.

FN738 FERC Stats. & Regs. at 31,839-40; mimeo at 595-99.

739 E.g., TDU Systems, APPA, Central Vermont, ELCON

740 E.g., TDU Systems, NRECA, Central Montana EC, SoCal Edison.

741 See also Coalition for Economic Competition at 47.

FN742 E.g., Central Vermont, Texaco, Carolina P&L.

743 80 F.3d 526 (D.C Cir. 1996) (Town of Norwood).

744 E.g., EEI, Utilities For Improved Transition, VEPCO, Coalition for Economic Competition.

745 The use of present revenues is reasonably workable from an administrative standpoint.

746 Our rationale here is equally applicable to APPA's argument that RSE should be based upon the price of wholesale power in a competitive market

747 In addition, Order No. 888 provides recovery of only the difference between the average annual revenues that the customer would have paid had it remained a customer (RSE) and the estimated competitive market value (CMVE) of the released power (i.e., the stranded cost). However, while the formula contemplates that the utility can sell the released power at the estimated competitive market value, the actual market value may be lower, increasing the risk that the utility will not be able to recover its stranded costs.

748 In Order No. 888, the Commission rejected arguments that return-related revenues be excluded from the revenue stream. The Commission found that such exclusion would effectively require shareholders to absorb stranded costs, which is contrary to the Commission's finding that a utility is entitled to an opportunity to fully recover legitimate, prudent and verifiable stranded costs. In this order, we reaffirm our earlier finding.

749 FERC Stats. & Regs. at 31,840; mimeo at 597.

750 Present revenues depend, of course, on both price and quantity. Most petitioners who dispute the use of present revenues argue, in some fashion or another, that present revenues are inappropriate because the costs included in present revenues may not equate to the costs incurred by the utility during L. These petitioners are arguing about price.

751 Condition 2 requires use of the most recent twelve months of revenue if there has been a rate change. See FERC Stats. & Regs. at 31,840; mimeo at 597.

752 If RSE and CMVE are calculated on a present value basis, and the difference between the two is multiplied by L, the result constitutes the customer's SCO. This present value is the amount to be paid under the lump-sum payment option. If the customer chooses another payment option, additional time-value calculations would be required to match the customer's stranded cost obligation with a series of payments made over time.

753 The utility is entitled to recover no more than the present value of the revenue stream (less the competitive market value) it would have received had the customer remained on its system.

754 FERC Stats. & Regs. at 31,842; mimeo at 604

755 We note that in a section 206 proceeding initiated by a customer, Order No. 888 requires that estimates of stranded cost liability shall include the information necessary to allow the utility to understand the basis of the estimate. (Mimeo at 610 referencing Implementation Procedure (2)). The implementation requirements in Implementation Procedure (2) apply not only to a utility making a stranded cost estimate, but also to a customer filing under section 206. Therefore, in case Order No. 888 is unclear, we clarify that a customer filing under section 206 and choosing CMVE Option 2 must include a copy of its replacement contract and any other information necessary to determine the equivalence of its replacement contract.

756 If the customer decides not to exercise either CMVE Option 2 or the marketing/brokering option, the customer still would be permitted to challenge the reasonableness of the utility's CMVE estimate (under CMVE Option 1) as well as the reasonableness of the other aspects of the utility's stranded cost estimate.

757 For estimation purposes the utility should still provide its CMVE on a market value basis for both capacity (fixed) and energy (variable) so that customers can better understand the basis for the utility's estimate.

758 This is so because, throughout the period that the customer is trying to find a buyer, the utility can sell the released capacity and energy only in the short-term market, most likely at a lower price than it could receive in a longer-term market. The utility is limited to the short-term market because the capacity must be available when the customer finds a buyer.

759 Freedom Energy and ELCON reference a study conducted under the aegis of the Massachusetts Attorney General to support their position that the future benefits of deregulating sales of energy and capacity will produce a net gain for utilities that is often sufficient to offset the full amount of any potential stranded costs.

760 16 U.S.C. §824(a).

761 See also Wisconsin Municipals. ***12427**

762 FERC Stats. & Regs. at 31,840; mimeo at 598.
763 As discussed in Section VI., we will treat SBA's request as a motion for reconsideration.
764 18 CFR 385.214 (1996).
765 See FERC Stats. & Regs. at 31,845-46; mimeo at 614-15.
766 Sec FERC Stats. & Regs. at 31,846-47; mimeo at 615-18.
767 Mimeo at 768.
768 FERC Stats. & Regs. at 31,849-50; mimeo at 624-26. The definition of "retail stranded cost" contains a similar requirement that the retail customer must become, in whole or in part, an unbundled retail transmission services customer of the public utility from which the customer previously received bundled retail services. We said that we would retain it for the same reasons discussed above.
FN767 As we clarify in this Order, there is not a sufficient nexus to Commission-required transmission access in such circumstances. The Commission's decision not to allow utilities to seek recovery of stranded costs under the provisions of Order No. 888 if the customer leaves its historical power supplier by exercising power supply options that do not rely on access to the former supplier's transmission is based on the absence of a direct causal nexus between stranded costs and the availability and use of Commission-required transmission access. Self-generation and access to another utility's transmission system would have been options prior to the Rule.
770 FERC Stats. & Regs. at 31,850; mimeo at }626-27.
771 Utilities For Improved Transition at 17.
772 Both note that this is the prudence standard that the Commission applied in Order No 636.
773 For the same reason, we will reject Southern's request that we establish a rebuttable presumption of prudence that must be overcome by the departing customer.
774 See Minnesota Power & Light Company, Opinion No. 86, 11 FERC 61,312 at 61,644-45 (1980).
FN775 Id. at 61,644; Anaheim Riverside, et al. v. FERC, 669 F.2d 799, 809 (D.C. Cir. 1981).
FN776 A utility has an ongoing prudence obligation. As pointed out in Order No. 888, although an investment or a contract may have been prudently incurred, it may become imprudent at a later point in time not to dispose of assets or not to buy-out contracts that have become uneconomic, assuming this results in net benefits to customers.
FN777 See Canal Electric Company, 47 FERC 61.044 at 61,127, reh'g denied, 49 FERC 61,069 (1989) (if a party raises prudence issues in a later proceeding, any future finding concerning prudence will have no effect on past rates).
778 Although we will not go so far as to characterize these costs as "per se prudent" (as requested by PSE&G), in effect, the result is the same because we will not allow the prudence of such costs to be relitigated.
779 See New England Power Company, 31 FERC 61,047 at 61,081-84 (1985), aff'd sub nom., Violet v. FERC, 800 F.2d 280. 282-83 (1st Cir. 1986). We note that this is the same standard that the Commission has used for reviewing the prudence of a pipeline's Order No. 636 gas supply realignment costs. See Texas Eastern Transmission Corporation. 65 FERC 61,363 (1993).
FN780 New England Power Company, 31 FERC at 61,084.
FN781 Id.
782 FERC Stats. & Regs. at 31,851-52; mimeo at 631-32.
FN783 See, e.g., Consolidated Edison Company of New York, Inc. and Central Hudson Gas & Electric Corp., 72 FERC 61.184 at 61,891 (1995) (ConEd).
784 72 FERC at 61,891.
785 FERC Stats. & Regs. at 31,853-54; mimeo at 636-38. The Commission also noted that non-public utility entities could request that the Commission find that they can satisfy the reciprocity condition without meeting all or some of the requirements that public utilities must meet.
786 FERC Stats. & Regs. at 31,854; mimeo at 637-38.
787 Black Creek Hydro, Inc. (Black Creek), 77 FERC 61,232 (1996); Midwest Energy, Inc., 77 FERC 61,208 (1996).
788 FERC Stats. & Regs. at 31,854-55; mimeo at 640.
789 FERC Stats. & Regs. at 31,855; mimeo at 642.
790 FERC Stats. & Regs. at 31,856; mimeo at }644-45.
791 FERC Stats. & Regs. at 31,857-58; mimeo at 648-49.
792 The Commission noted, however, that PMAs are transmitting utilities subject to requests for mandatory transmission services under section 211 of the FPA.
FN793 FERC Stats. & Regs. at 31,858; mimeo at 650-51
794 The Commission noted, however, that TVA is a transmitting utility subject to requests for mandatory transmission services under section 211 of the FPA.

FN795 FERC Stats. & Regs. at 31,858-59; mimeo at 651-52.

796 FERC Stats. & Regs. at 31,859; mimeo at }654-55.

797 FERC Stats. & Regs. at 31,860; mimeo at 656.

798 FERC Stats. & Regs. at 31,682-84; mimeo at 136-142.

FN799 Union Electric argues that

[t]he dramatic changes in the regulatory scheme set forth in the final rules impose extensive constraints on Union Electric's use of its own property, forcing Union Electric to throw open its transmission system to use by third parties, dictating the terms and conditions of that usage and, in the process, providing for the physical occupation of Union Electric's transmission system by third parties' facilities and power. (Union Electric at 59).

However, as Union Electric's own words demonstrate, these so-called dramatic changes are no more than a summary of the Commission's current authority and the Commission's current regulation of public utilities. Under the FPA, Union Electric can only provide non-unduly-discriminatory jurisdictional services to third parties and must obtain Commission approval of the rates, terms and conditions pursuant to which it provides such service. Moreover, under Order No. 888, third parties may "physically occupy" Union Electric's transmission system only pursuant to the terms of Union Electric's tariff and contracts entered into with Union Electric, just as third parties previously had the right to "physically occupy" its transmission system.

Finally, we are confused about Union Electric's argument in that in the pending merger proceeding involving its proposed merger with Central Illinois, it argues that the open access tariff of the merged company will be used to mitigate market power. See El Paso Electric Company and Central and South West Services Inc., 68 FERC 61,181 at 61,914 (1994), dismissed, 72 FERC 61,292 (1995). Union Electric cannot argue that the tariff mitigates market power at the same time it argues that the requirement to have the tariff is prohibited as an unconstitutional taking of property.

800 See, e.g., FPC v. Hope Natural Gas Company, 320 U.S. 591 (1944). Moreover, to the extent Union Electric's facilities are used for public service, Union Electric is entitled to recover all prudently invested capital in the public utility enterprise. We have not changed that principle.

FN801 FPC v. Texaco, 417 U.S. 380, 391-92 (1974); see also FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 585 (1942).

FN802 All public utilities subject to Commission jurisdiction were required to file open access compliance tariffs, including the rate to be charged for various types of transmission service, by July 9, 1996.

803 With specific regard to Cleveland and CEI, we note that the Commission has expended considerable resources over the years dealing with and resolving a significant number of section 205 and 206 proceedings in which these companies contested a plethora of issues. As the D.C. Circuit noted, these two entities have a particularly hostile relationship. City of Cleveland v. FERC, 773 F.2d 1368, 1371 (1985). This has led to a situation where these contentious entities are more likely to contest issues before the Commission than to resolve them. Since 1993 alone, the Commission has addressed and resolved at least 9 proceedings involving disputes between Cleveland and CEI. Indeed, at this time, the Commission has only several ongoing proceedings involving disputes between these entities. In addition, the parties are in disagreement over transmission issues in the pending merger application involving CEI and Ohio Edison.

804 Ohio Valley states that the facility is now leased by the United States to the United States Enrichment Corporation.

FN805 Dayton filed a motion to reject Ohio Valley's request for rehearing, arguing that it was really an application for waiver. (Dayton Motion to Reject).

806 Order Clarifying Order Nos. 888 and 889 Compliance Matters, 76 FERC 61,009 (1996).

807 E.g., VT DPS, Valero, APPA.

808 American Forest & Paper at 24.

809 FERC Stats. & Regs. at 31,860; mimeo at 657-58 (footnote omitted).

810 The EIS also conducts sensitivity analyses of how projected air emissions might change if key assumptions in the analysis are changed. These analyses include two frozen efficiency reference cases which represent a world in which: (1) the Commission reverses current pro-competitive transmission policy (inconsistent with congressional mandates under EPAct); (2) states cease to adopt programs to improve industry efficiency; and (3) electric companies cease to improve operations or to enter into mutually beneficial transactions.

811 Letter of May 22, 1996 from Mary Nichols, Assistant Administrator for Air and Radiation, EPA, to Kathleen McGinty, Chair, CEQ.

812 Letter of May 13, 1996, from Carol Browner, Administrator, EPA to Kathleen McGinty, Chair, CEQ.

813 Order Responding to Referral to Council on Environmental Quality, 75 FERC 61,208 at 61,691-92 (1996).

FN814 Letter of June 14, 1996 from Kathleen McGinty, Chair, CEQ, to Carol Browner, Administrator, EPA and Elizabeth Moler, Chair, FERC.

815 FEIS at 2-1 and 2-2.

816 To date, the Commission has issued six proposed orders and four final section 211 orders. Id. at 2-1

817 See also Northwest Coalition for Alternatives to Pesticides v. Lyng, 844 F.2d 588, 591 (9th Cir. 1988).

818 Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc., 435 U.S. 519, 551 (1978); Laguna Greenbelt, Inc. v. U.S. Department of Transportation, 42 F.3d 517, 524 (9th Cir. 1994).

FN819 National Wildlife Federation v. Whistler, 27 F.3d 1341, 1345 (8th Cir. 1994).

FN820 Laguna Greenbelt, supra, 42 F.2d at 524. In that case, involving construction of a tollroad, Laguna contended that the EIS ignored a smaller, four-lane alternative. The EIS addressed this proposal, explaining that it was rejected because a four lane highway would not meet the project's goal of reducing traffic congestion. The court found that the proposal was thus properly rejected as not reasonably related to the purposes of the project. Id. at 524-25

821 FERC Stats. & Regs. at 31,863; mimeo at 665-66 (footnote omitted).

822 Although cast as use of an inappropriate "no action alternative", the Joint Commenters' point goes to the appropriateness of the base case used in the analysis.

823 This analysis is described as a sensitivity analysis because it examines how projected air emissions might change if key assumptions in the analysis are altered.

824 DEIS at 3-2 through 3-5; FEIS at 3-2 through 3-5.

825 The PUC appears to base its rehearing comments on the DEIS; the points it asserts on rehearing ignore extensive responses to these comments in the FEIS. For example, the FEIS responds to the following specific points that are now raised by the PUC on rehearing: Impact of the rule on Pennsylvania coal production (FEIS at J-22); impact on reliability (FEIS at J-26); impact on stranded benefits (FEIS at J-30); impact of assumed increased volume of transmission transactions (FEIS at J-39); claim that the analysis must consider impact of Group II boiler rule and Phase III of the MOU (FEIS at J-49); claim that FEIS makes conclusory statements (FEIS at J-60); claim that heat rate assumptions are optimistic (FEIS at J-63); claim that transmission usage prices are circular (FEIS at J-65); claim that availabilities are speculative (FEIS at J-67); claim that reserve margins are unlikely to fall as far as the FEIS assumes (FEIS at J-68); concerns about choice of linear modeling (FEIS at J-73); concerns about differing emission standards in Pennsylvania and West Virginia (FEIS at J-92); claim that the Rule is inconsistent with Title I of the Clean Air Act (FEIS at J-97).

826 FEIS at 3-8 through 3-11.

827 As explained in the FEIS at 3-13 through 3-15 and as discussed below, the movement of power from low cost sources is limited not only by the physical constraints of the transmission system, but also by institutional impediments such as lack of access to needed transmission As a result, in a model like that used in the EIS, where flows are based on minimizing costs subject to physical constraints, the model will typically overestimate the amount of power flowing from low-cost sources of generation. The Commission chose to address this by developing a "usage price" to raise the variable cost to simulate the effect of observed barriers to power flows between regions. The usage price is a proxy for transmission barriers, not an attempt to estimate or model an actual transmission price. The usage price was calibrated to produce actual historical flows of electricity, not costs of transmission. As such it has almost no relationship with actual transmission prices.

FN828 Id

829 Id. at 3-18.

830 Id. at J-63 and J-67.

831 Id. at 3-16 and 3-17. Table 3-4 is found on page 3-17.

832 Id. at 3-25.

833 Id. at 3-5 through 3-8.

834 Id. at 3-7 through 3-8.

835 The Joint Commenters claims as to the Constant-Price-Differential Base Case are probably meant as a reference to the Competition-Favors-Gas Scenario.

836 FEIS Chapter 6.

FN837 Id at Table 6-19 (page 6-23) and Table 5-18 (page 5-16), respectively.

838 FERC Stats. & Regs. at 31,872 n.974; mimeo at 691-92 n.974.

839 Edison Electric Institute, Assessment of Greenhouse Gas Emissions Policies on the Electric Utility Industry: Costs, Impacts and Opportunities, prepared by ICF Resources, January 1992.

FN840 See also FEIS Sections 3.4.2.1 and J.7 1.

841 The EIS and Order No. 888 examine the specific mitigation proposals advanced by the Center for Clean Air Policy, the EPA, the Joint Commenters, the Project for Sustainable FERC Energy Policy, and the Department of Energy. FEIS at 7-28 through 7-43; FERC Stats. & Regs. at 31,877-82; mimeo at 705-17. The Commission concluded that the mitigation measures urged by the commenters are unwarranted, and that mitigation of the Rule is not required. Of the commenters advancing specific mitigation proposals in comments on the draft EIS, only the Joint Commenters seek rehearing of Order No. 888 on environmental issues. The Joint Commenters do

not take issue on rehearing with the Commission's rejection of its mitigation proposal, but rather mounts a broad attack in which it asserts that the Commission has failed to properly consider and disclose the potential environmental effects of the Rule, and that the Commission's decision that it lacks authority to implement mitigation is contrary to law.

842 FEIS at 7-47 and 7-48.

843 Id. at 7-49.

844 The New York Attorney General wrote to the Commission on May 13, 1996 expressing concern about the potential environmental effects of the Rule Its filing does not appear to constitute a request for rehearing, but it is treated here as such.

845 This aspect of the Joint Commenters' argument is addressed below.

846 FERC Stats. & Regs. at 31,862-63; mimeo at 663-65 (footnotes omitted).

847 Id. at 31,863; mimeo at 665.

848 Id. at 31,863-64; mimeo at 665-67 (footnotes omitted).

849 The FEIS at page 7-8 discusses EPA's authority under the Clean Air Act to remedy the interstate transport of air pollution. Section 176A provides that whenever EPA has reason to believe that the interstate transport of air pollutants from one or more states contributes significantly to a violation of national ambient air quality standards in one or more other states, it may establish a transport region for such pollutant. The transport commission is charged statutorily with assessing the degree of interstate transport of the pollutant or precursors to the pollutant throughout the transport region, assessing strategies for mitigating the interstate pollution, and recommending to the EPA Administrator measures to ensure that the relevant State Implementation Plans (which every state is required to have in place to address air pollution) meet the requirements of the Clean Air Act.

A transport commission may request the Administrator to issue a finding under section 110(k)(5) that the SIP for one or more of the states in the transport region is substantially inadequate to meet the requirements of section 110. The Administrator must approve or disapprove such a request within 18 months of its receipt.

Upon approval of recommendations submitted by the transport commission, the Administrator must issue to each state in the OTR to which a requirement of the approved plan applies, a finding under section 110(k)(5) that the implementation plan for such state is inadequate to meet the requirements of section 110. Such finding shall require each such state to revise its SIP to include the approved additional control measures within one year after the finding is issued.

850 Order Responding to Referral to Council on Environmental Quality, 75 FERC 61,208 at 61,691-92 (1996).

851 FEIS at 7-10 through 7-11.

852 We note in this regard that in a recently completed rulemaking promulgating standards for the second phase of the Nitrogen Oxides Reduction Program under Title IV of the Clean Air Act, EPA authorized states to adopt a NO_X cap and trading program under certain circumstances. "Acid Rain Program: Nitrogen Oxides Emission Reduction Program", 61 FR 67112, 67163 (1996).

853 62 FR 1420 (1997).

FN854 Id. at 1423.

FN855 Id

856 See, e.g., Marsh v. Oregon Natural Resources Council, 490 U.S. 360 (1989); Sierra Club v. Marita, 46 F.3d 606, 623-24 (7th Cir. 1995); Inland Empire Public Lands Council v. Schultz, 992 F.2d 977, 981 (9th Cir. 1993).

857 Kleppe v. Sierra Club, 427 U.S. 390 (1976).

858 FERC Stats. & Reg. at 31,890-91; mimeo at 740-43 (footnotes omitted). The FEIS noted in this regard at page J-93 that:

Many factors cause generation sources to have differing costs. Some states impose taxes on generators that others do not. Some fuels are taxed differently than others (e.g., renewable generators such as wind power receive tax incentives that fossil generators do not while fossil fuels receive other tax advantages that renewables do not.) Such differences cannot be said to be unduly discriminatory, especially when they are sanctioned, or even required, by the actions of the Congress or state authorities. If the Commission attempted to "level" all of the "playing fields" it would be unable to judge any rate to be just and reasonable. Further, traditional rates are not determined through competitive processes but on a cost of service basis. Not all rates have to be determined to be competitive in order to be judged just and reasonable. * * *

859 FEIS at ES-9, 3-1.

860 Id. at 3-1.

861 Id. at 5-15.

862 FERC Stats & Regs. at 31,634; mimeo at 1.

FN863 FEIS at ES-13 through ES-16.

864 The discussion of the economic benefits of the Rule in found in the FEIS at ES-13 through ES-16 and 5-64 through 5-75.

865 FEIS at 5-64.

866 In point of fact, the overall thrust of the FEIS is to analyze and discuss the projected costs of the Rule. The discussion of the projected benefits of the Rule comprise a tiny fraction of that discussion. The Joint Commenters dissatisfaction with the results of the analysis does not mean that the projected impacts of the Rule were not discussed in full.

867 Public Utilities Commission, 900 F.2d at 282 (brackets, ellipses, and emphasis in original).

868 FEIS at 5-64 and 5-75 through 5-76.

869 Id. at 5-75 through 5-76.

872 The CEQ regulations, 40 CFR 1508.14 (1996), state that "economic or social effects are not intended by themselves to require preparation of an environmental impact statement." See also Panhandle Producers & Royalty Owners Association v. Economic Regulatory Administration, 847 F.2d 1168, 1179 (5th Cir. 1988); Olmstead Citizens for a Better Community v. United States, 793 F.2d 201, 205 (8th Cir. 1986).

FN871 The CEQ regulations, 40 CFR 1508.14 (1996), provide that "[w]hen an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment." This limitation has been read very strictly. In Stauber v. Shalala, 895 F.Supp. 1178, 1194 (W.D.Wis.1995), for example, the court responded to a claim that a proposed action would cause both environmental and socioeconomic harms and that for this reason an EIS was necessary. The court found that:

This assertion is insufficient to satisfy the "interrelatedness" requirement of §1508.14. I read 40 C.F.R. §1508.14 to mean that it is only after an agency determines that the socioeconomic impact of the proposed agency action is likely to cause environmental harms itself that the agency needs to discuss the socioeconomic effects in the environmental impact statement. See Breckinridge v. Rumsfield, 537 F.2d 864, 866 (6th Cir.1976) (accord), cert. denied, 429 U.S. 1061, 97 S.Ct. 785, 50 L.Ed.2d 777 (1977). This reading fully comports with the plain language of the regulation. * * *

FN872 It is interesting to note in this regard that Pennsylvania recently adopted electric restructuring legislation of its own establishing retail wheeling. It thus became the fourth state in the Northeast to do so; the others are Massachusetts, Rhode Island, and New Hampshire. The legislation was described by the Governor of Pennsylvania as creating a "critical competitive advantage" for Pennsylvania. The Energy Daily, December 4, 1996.

873 Metropolitan Edison Co., 460 U.S. at 769. PANE also asserted that NEPA required consideration of "[t]he perception, created by the accident, that the communities near Three Mile Island are undesirable locations for business or industry, or for the establishment of law or medical practice, or homes compounds the damage to the viability of the communities." Id. at 770 n.2.

874 Id. at 772-73 (emphasis in original) (footnote omitted). The continuing validity of the argument that socioeconomic effects are to be considered in an EIS if the federal action has a primary impact on the natural environment is doubtful. The court in Olmsted Citizens for a Better Community v. United States, 793 F.2d 201, 206 (8th Cir. 1986) stated that:

[I]t is unlikely that such a distinction survives the recent Supreme Court holding in Metropolitan Edison. That decision, as discussed above, was based on congressional intent, and there is no suggestion that Congress contemplated that the process it designed to make agencies aware of the consequences of their actions with regard to the physical environment would be converted into a process for airing general policy objections anytime the physical environment was implicated. Such a rule would divert agency resources away from the primary statutory goal of protecting the physical environment and natural resources. * * *

875 FERC Stats. & Regs. at 31,895; mimeo at 754.

876 Id. at 31,895-96; mimeo at 755-56 (footnote omitted).

877 In issuing a negative determination, the Commission noted that it questioned whether the CZMA applies to economic regulatory activities involving interstate electric rates and service. The Commission also noted that Connecticut had waived its right to request a consistency determination or negative determination by failing to notify the Commission of its request within 45 days from receipt of the notice of the federal activity. The Commission concluded that it did not waive those arguments by providing Connecticut with a consistency determination and negative determination.

878 5 U.S.C. §601-612.

FN879 Open Access Rule, 61 FR 21540 at 21691 (May 10, 1996), FERC Stats. & Regs. 31,036 at 31,898 (1996).

880 The SBA filed its Request for Rehearing on June 10, 1996, after the statutory deadline for the filing of such a pleading. Accordingly, we will not accept its pleading as a request for rehearing but will, instead, treat it as a motion for reconsideration.

On November 1, 1996, NRECA filed a supplement to its Requests for Rehearing and Clarifications. We will reject the supplement to the request for rehearing as barred by the 30 day time limit for filing petitions for reconsideration. Neither the Commission nor the courts can waive a failure to comply with the statute. See Platte River Whooping Crane Critical Habitat Maintenance Trust v. FERC, 876 F.2d 109, 113 (D.C. Cir. 1989); Tennessee Gas Pipeline Company v. FERC, 871 F. 2d 1099, 1107 (D.C. Cir. 1989); Boston Gas Company v. FERC, 575 F.2d 975 (1st Cir. 1978). Accord Commonwealth Electric Company v. Boston Edison Company, 46 FERC 61,253 at 61,757, reh'g denied, 47 FERC 61,118 (1989). We will accept NRECA's supplemental request for clarifications.

FN881 NRECA at 42-43.

882 NRECA at 44.

FN883 Capacity Reservation Open Access Transmission Tariffs, Notice of Proposed Rulemaking, IV FERC Stats. & Regs Proposed Regulations 32,519 (1996), 61 FR 21847 (May 10, 1996) (Capacity Reservation).

FN884 We will discuss NRECA's arguments concerning the OASIS Final Rule in our order on rehearing in that proceeding. We reject NRECA's reference to the Capacity Tariff Reservation NOPR as inapposite to this proceeding. We have invited comments on the proposed Capacity Reservation Open Access Transmission Tariffs (Capacity Reservation, IV FERC Stats. & Regs. Proposed Regulations at 33,235, 61 FR 21847 at 21853) and will discuss those comments in the appropriate proceeding.

885 SBA Request for Reconsideration at 5. The SBA defines a small public electric utility as one that disposes of 4 Million MWh per year. 13 CFR 121.201.

886 773 F.2d 327 (D.C. Cir. 1985) (Mid-Tex).

887 FERC Stats. & Regs. at 31,897 (1996)(footnotes omitted); mimeo at 758-59.

888 Id. at n.1078.

889 Id. at n.1081.

890 Mid-Tex, 773 F. 2d at 340-43.

891 Id.

892 The Commission's waiver policy follows the SBA definition of small electric utility. See 5 U.S.C. §601(3) and 601(6) and 15 U.S.C. §632(a). The RFA defines a small entity as one that is independently owned and not dominant in its field of operation. See 15 U.S.C. §632(a). The SBA defines a small electric utility as one that disposes of 4 million MWh or less of electric energy in a given year. See 13 CFR 121.601 (Major Group 49-Electric, Gas and Sanitary Services) (1995).

FN893 Northern States Power Company, 76 FERC 61,250 (1996); Central Electric Cooperative, et al., 77 FERC 61,076 (1996); Black Creek Hydro, et al., 77 FERC 61,232 (1996); Dakota Electric Association, et al., 78 FERC 61,117 (1997); Soyland Power Cooperative, Inc., et al., 78 FERC 61,095 (1997); Niobrara Valley Electric Membership Cooperation, Docket Nos. OA96-146-001 and ER97-1412-000, Letter Order issued February 26, 1997.

FN894 These total more that the 19 small public utilities we referenced in Order No. 888 because, since the issuance of that order, several entities have repaid their RUS-financed debt and become public utilities subject to our jurisdiction and several new public utilities have been created as the result of the construction of new facilities.

895 See United Distribution Companies v. FERC, 88 F.3d 1105, 1170 (July 16, 1996) ("FERC had no obligation to conduct a small entity impact analysis of effects on entities which it does not regulate.").

896 NRECA at 44.

897 Stranded costs could also conceivably arise as a result of an ordered interconnection under section 210. However, the rates for such an interconnection would be established pursuant to section 212 and could therefore also include stranded costs.

898 Although the Commission would not determine the rate, including the stranded cost component of the rate, of a non-public utility, we would review a public utility's claim that it is entitled to deny service to a non-public utility because the stranded cost component of the non-public utility's transmission rate is being applied in a way that violates the principle of comparability.

899 One need not respond to a collection of information unless it displays a valid OMB control number. The OMB control number for this collection of information is 1902-0096.

1 Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636-C, 78 FERC 61,186 (1997).

FN2 Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, Order No. 528-A, 54 FERC 61,095 (1991).

End of Document

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Parts 35 and 37

(Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890)

Preventing Undue Discrimination and Preference in Transmission Service

(Issued February 16, 2007)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule

SUMMARY: The Federal Energy Regulatory Commission is amending the regulations and the pro forma open access transmission tariff adopted in Order Nos. 888 and 889 to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. The final rule is designed to: (1) strengthen the pro forma open-access transmission tariff, or OATT, to ensure that it achieves its original purpose of remedying undue discrimination; (2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and (3) increase transparency in the rules applicable to planning and use of the transmission system.

EFFECTIVE DATE: This rule will become effective **[insert date 60 days after publication in the FEDERAL REGISTER].**

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Preventing Undue Discrimination and Preference in Transmission Service — Docket Nos. RM05-17-000, RM05-25-000

ORDER NO. 890

FINAL RULE

(Issued February 16, 2007)

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resources and network loads in the same manner as any network customer. Occidental offers no explanation why the existing requirement of section 28.2 is not sufficient to address its concerns.

b. Behind the Meter Generation

1614. In Order No. 888, in response to customers with load served by "behind the meter" generation that sought to eliminate such load from their network calculation, the Commission found that a customer may exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system. The Commission determined, however, that customers electing to do so must seek alternative transmission service, such as point-to-point transmission service, for any load that has not been designated as network load for network service.[911] In Order No. 888-A, the Commission stated that it would permit a network customer to either designate all of a discrete load as network load under the network integration transmission service or to exclude the entirety of a discrete load from network service and serve such load with the customer's behind the meter generation and/or through any point-to-point transmission service.[912]

1615. The Commission did not address the subject of behind the meter generation in the NOPR. A few commenters nonetheless proposed revisions to the pro forma OATT to

[911] Order No. 888 at 31,736.

[912] Order No. 888-A at 30,258-61.

require netting of a network customer's behind the meter generation against their network load as described in more detail below.

Comments

1616. Some commenters argue that, in order to meet the objective of eliminating discrimination in the provision of open access transmission service, the Commission must require comparable treatment between retail native load and network customers by allowing network customers to net behind the meter generation against their network load.[913] Specifically, such commenters argue that the Commission should modify the current pricing rules for network service to allow an LSE's load ratio share to reflect the reduction in load caused by behind the meter generation serving retail load.[914] In support of this position, these commenters argue that assigning transmission-related costs to customers that do not rely on the transmission provider's system to serve load is inconsistent with the Commission's cost-causation principles.[915] For example, CAC/EPUC contends that customer generation does not cause the transmission provider to incur costs when power is not being sold to or taken off the grid. Similarly, AMP-

[913] E.g., TAPS, TDU Systems, AMP-Ohio, and CAC/EPUC.

[914] TDU Systems and TAPS also cite Consumers Energy, 98 FERC ¶ 61,333 at 62,410 (2002) (requiring that a transmission provider's retail load associated with behind the meter generation be included in the transmission provider's load ratio share to ensure comparability between transmission providers and network customers in the calculation of load ratio share).

[915] E.g., AMP-Ohio, CAC/EPUC, and TAPS.

Ohio argues that it is inappropriate to assign a full load ratio share of transmission-related costs to behind the meter generation customers that do not use the network to the full extent of their load ratio shares.[916] Further, CAC/EPUC asserts that measuring the customer's use of the transmission system at the customer's meter would be appropriate as it would demonstrate that, if no power flows to the customer from the grid occur, that customer has not used nor caused costs to be incurred by the grid for the delivery of its energy requirements.

1617. Some commenters note that the Commission has approved PJM netting provisions that apply to behind the meter generation used by non-retail and wholesale customers to serve load.[917] These same commenters further observe that PJM has filed with the Commission to expand participation in its behind the meter generation netting program to include municipal, electric cooperatives, and electric distribution transmission customers who take network service on the PJM system pursuant to a settlement agreement filed by PJM on October 24, 2005 in Docket No. EL05-127-000.[918]

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[916] Citing Occidental Chemical Corporation v. PJM Interconnection, L.L.C., and Delmarva Power & Light Company, 102 FERC ¶ 61,275 at P 14 (2003) ("Access charges for use of PJM's transmission system should be allocated to network customers based on a network customer's actual use of PJM's system, consistent with the principle of cost-causation."); PJM Interconnection, L.L.C., 107 FERC ¶ 61,113, at P 28 (2004).

[917] E.g., AMP-Ohio, TAPS, and TDU Systems (citing PJM Interconnection, L.L.C., 107 FERC ¶ 61,113 (2004), reh'g denied, 108 FERC ¶ 61,032 (2004) (PJM)).

[918] This settlement agreement was accepted in PJM Interconnection, L.L.C., 113 FERC ¶ 61,279 (2005).

1618. Further, both TAPS and AMP-Ohio argue that behind the meter generation provides benefits to the transmission provider that should be taken into account as part of system planning obligations. For instance, AMP-Ohio asserts that utility planning can and should be able to take into account the ability of customers to reduce their load on the system with behind the meter generation. TDU Systems also notes PJM's representation that allowing municipal and electric cooperative system participation in behind the meter generation netting programs increased reliability and demand response opportunities on PJM's system.[919] Similarly, TAPS observes that PJM's rules reserve the right to call upon non-retail behind the meter generation under certain conditions.

Commission Determination

1619. The Commission is not persuaded to require transmission providers to allow netting of behind the meter generation against transmission service charges to the extent customers do not rely on the transmission system to meet their energy needs. Commenters in this proceeding have not provided any different arguments that were not fully considered and addressed in Order No. 888, et al. The existing pro forma OATT already permits transmission customers to exclude the entirety of a discrete load from network service and serve such load with the customer's behind the meter generation and through any needed point-to-point transmission service, thereby reducing the network customer's load ratio share. Therefore, the Commission's existing policy already

[919] PJM Interconnection, L.L.C., 113 FERC ¶ 63,024 (2005).

provides customers with the opportunity to reduce network service costs to the extent a customer is not relying on the transmission system to meet its energy needs.[920] As the Commission concluded in Order No. 888-A, transmission customers ultimately must evaluate the financial advantages and risks and choose to use either network integration or firm point-to-point transmission service to serve load.[921] We believe it is most appropriate to continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis, as the Commission did in the PJM proceeding cited by the commenters.

8. Transmission Curtailments

1620. In the NOPR, the Commission proposed no changes to the pro forma OATT with respect to curtailment provisions for point-to-point service (set forth in sections 13.6 and 14.7) and network service (set forth in section 33). These provisions establish the terms and conditions under which a transmission provider may curtail service to maintain reliable operation of the system. Though several commenters claimed in response to the NOI that the reasons for transmission curtailments are difficult to discern, they did not provide sufficient detail to indicate whether that difficulty is a result of inadequate disclosure regulations, inadequate compliance with those regulations, or some other

[920] We note that EEI responds to allegations of undue discrimination in the calculation of load ratio share costs in the OATT Definitions section of this Final Rule.

[921] Order No. 888-A at 30,260-61.

61 FR 21540-01
RULES and REGULATIONS
DEPARTMENT OF ENERGY
Federal Energy Regulatory Commission
18 CFR Parts 35 and 385
[Docket Nos. RM95-8-000 and RM94-7-001; Order No. 888]

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

Friday, May 10, 1996

***21540** Issued April 24, 1996.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing a Final Rule requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. The Final Rule also permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and Federal Power Act section 211 transmission services. The Commission's goal is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.
EFFECTIVE DATE: This Final Rule will become effective on July 9, 1996.

FOR FURTHER INFORMATION CONTACT:

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Michael A. Coleman (Technical Information), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 208-1236.

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in the Public Reference Room at 888 First Street, NE., Washington, DC 20426.
The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing 202-208-1397 if dialing locally, or 1-800-856-3920 if dialing long distance. CIPS is also available through the Fed World system (by modem or Internet). To access CIPS, set your communications software to 19200, 14400, 12000, 9600, 7200, 4800, 2400, or 1200 bps, full duplex, no parity, 8 data bits and 1 stop bit. The full text of this order will be

the use of a complex seasonal calculation, which appears to benefit wind energy. NY Com and Missouri-Kansas Industrials also express a preference for seasonal pricing models.

Commission Conclusion

We conclude that the load ratio allocation method of pricing network service continues to be reasonable for purposes of initiating open access transmission. Network service permits a transmission customer to integrate and economically dispatch its resources to serve its load in a manner comparable to the way that the transmission provider uses the transmission system to integrate its generating resources to serve its native load. Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to non-discrimination. We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning. Moreover, we recognize that alternative allocation proposals may have merit and welcome their submittal by utilities in future rate applications. They will be evaluated on a case-by-case basis and decided on their merits.

As to the concerns raised by AEC & SMEPA and NRECA about pancaked rates for network service provided to load served by more than one network service provider, we have stated that if a customer wishes to exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system, it may do so.[FN440] Customers that elect to do so, however, must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by "behind the meter" generation that seek to eliminate the load from their network load ratio calculation.

As noted, the most frequent comment is that the network and point-to-point services should be priced on a similar basis. This concern is addressed in the next section.

c. Annual System Peak Pricing for Flexible Point-to-Point Service

Comments

Commenters express concern that, if annual system peak capability is used to determine rates for point-to-point service and 12 CP is used to allocate costs for network service, point-to-point service may be underpriced relative to network service.[FN441] Therefore, many commenters propose pricing both services on the same basis.

EEI argues that flexible point-to-point service provides a premium service at a discount price. Therefore, EEI would increase the price unless the Commission either (1) eliminates the flexibility or (2) allows network customers to make non-firm sales at no additional charge. It recommends use of 12 CP for pricing both network and point-to-point service, but would credit point-to-point revenues to the cost of service for network and native load to avoid over-collection from contract demand point-to-point users. Alternatively, EEI contends that point-to-point service could use annual system peak capability pricing with a ratchet,[FN442] although EEI believes that 12 CP reflects the premium nature of long-term transmission. Under this alternative method, EEI notes that long-term non-flexible point-to-point service would use annual system peak pricing, while short-term service should be based on "up to" (ceiling) rates. In essence, EEI proposes a two-tier point-to-point service, with the first tier (flexible service) of equal priority in all respects to network service.[FN443] Ohio Edison also claims that, as proposed, flexible point-to-point service is a more valuable service than network service because it would be priced lower than network service. To correct for this difference, Ohio Edison would impose a separate rate for point-to-point non-firm use.

According to NRECA, unless the same measure of demand is included in the calculation of network and point-to-point charges, actual revenue from these two firm services will be greater than the actual cost of service. FL Com believes that flexible point-to-point service allows a transmission customer to engage in network economy transactions without incurring a full network comparability standard is at odds with the Commission's non-conforming transmission pricing policy, particularly with respect to "and" pricing.

Commission Conclusion

Under the Final Rule pro forma tariff, we will allow transmission providers to propose any method of collecting expansion costs that is consistent with our transmission pricing policy. We disagree with ELCON's assertion that directly assigning the costs for expanding a constrained transmission system is necessarily unfair. As we stated in Northeast Utilities, if the cost of expansion is directly attributable to a customer's request for transmission service and the expansion would not be undertaken "but for" that customer's request, then it is reasonable to assign the cost of expansion to that customer. If we were not to allow the direct assignment of expansion costs to the customer causing the expansion, then other customers would subsidize the new customer's use of the transmission system. We continue to believe that "or" pricing sends the proper price signal to customers and promotes efficiency. Under the tariff, any assignment of future expansion costs must meet the standards for conforming proposals in the Transmission Pricing Policy Statement. Recovering expansion cost based upon "and" pricing will not be allowed.

Any request to recover future expansion costs will require a separate section 205 filing. The Commission will evaluate, on a case-by-case basis, who is responsible for expansion costs in those filings and whether direct assignment of those costs is appropriate.

f. Credit for Customers' Transmission Facilities

Comments

Most commenters agree that the Commission must clearly define when a network customer's transmission facilities warrant a credit from the transmission provider. Several commenters state that customers must bear the burden of demonstrating that their facilities are used by and useful to the transmission provider, provide direct benefits, and support the operation of the transmission system.[FN450] EEI cautions against providing a credit for facilities that may be integrated with, but of no effective benefit to, the operation of the bulk power system.

The costs associated with customer-owned facilities that are used by the transmission provider should, in PECO's opinion, be recovered from the transmission provider under the customer's own transmission tariff.

FPL cautions that the position of certain parties that transmission facilities warrant a credit if they would have been included in the transmission provider's rates could produce absurd results. It claims that it could actually end up paying a network customer with substantial transmission investment for the right to provide that customer service. FPL contends that it will receive absolutely no service from its network customers because FPL would not need, nor could it use, any of the customers' transmission facilities to integrate FPL's loads and resources. FPL argues that crediting under the so called "rate base" test obligates the transmission provider to purchase a load-ratio share of the customer's transmission facilities. FPL states that, under network service, the transmission provider and the network customer will not create a single system.

AEP recommends that a network customer receive a credit if its transmission facilities meet the following criteria: (1) At points of interconnection, there must be a through-flow of power from the network customer's system to the transmission provider's system under normal operating conditions; and (2) the customer's facilities must: (a) Increase the transfer capability of an interface on the transmission provider's system; (b) provide an alternative path for power flows during transmission facility outages, thus increasing the reliability or stability of the combined system; or (c) otherwise satisfy the transmission provider's planning criteria for the installation of network facilities.

WP&L argues for a broader standard and states that a transmission customer should be entitled to a credit if the transmission owner would have installed similar facilities to provide service for its own native load under similar circumstances. Florida Power Corp states that the credit for each facility should be determined on a case-by-case basis.

PacifiCorp argues that a utility may take advantage of the transmission credit and shift major transmission investment onto another transmitting utility and its transmission customers by simply becoming a network customer. PacifiCorp claims that such a situation may, for example, exist for BPA as a transmitting utility. According to PacifiCorp, preliminary studies indicate at least one potential network customer may be entitled to a transmission credit which would exceed that customer's charges for BPA's network integration service.

APPA, Blue Ridge, and Cajun maintain that a customer's facilities should be evaluated on a basis comparable to the facilities included in the rates of transmission providers in a region. APPA argues that a claim that the transmission customer's facilities do not benefit the transmission system must be weighed against the fact that some facilities included in the transmission provider's rate base may not directly benefit the transmission customer. Cajun advocates setting clear standards for the identification of customer-owned transmission facilities eligible for crediting and clear guidelines for determining the amount of the credit.

SMUD not only supports the credit under the network tariff, but also would extend the credit to facilities used to complete a transaction under the transmission provider's point-to-point tariff.

***21603 Commission Conclusion**

Because of the diverse concerns raised by the commenters, we are unable to resolve on the basis of this record the extent to which, or under what circumstances, cost credits related to customer-owned facilities would be appropriate under an open-access transmission tariff. We conclude that such credits are more appropriately addressed on a case-by-case basis, where individual claims for credits may be evaluated against a specific set of facts.

We stress that while certain facilities may warrant some form of cost credit, the mere fact that transmission customers may own transmission facilities is not a guaranteed entitlement to such a credit. The presumption of many commenters that a customer's subscription to transmission service somehow transforms the provider's and customer's systems into an expanded integrated whole to the mutual benefit of both is not a valid one. As we ruled in Florida Municipal Power Agency v. Florida Power & Light Company (FMPA), it must be demonstrated that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider. Specifically, we stated that:

The integration of facilities into the plans or operations of a transmitting utility is the proper test for cost recognition in such cases. The mere fact that a section 211 requestor has previously constructed facilities is not sufficient to establish a right to credits.[FN451]

The fact that a transmission customer's facilities may be interconnected with a transmission provider's system does not prove that the two systems comprise an integrated whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over those facilities—a key requirement of integration.[FN452] We also note that consistent with our ruling in FMPA, if a customer wishes not to integrate certain loads and resources, and thereby exclude them from their load ratio share of the allocated cost of the integrated system, it may do so. Customers that elect to do so, however, should recognize that they may need to secure alternative transmission arrangements such as point-to-point transmission service on an as-available basis in order to utilize those resources for reserves.

Where disputes over credits for customer-owned transmission facilities arise, we encourage all parties to first pursue alternative means to resolve their differences rather than seek formal resolution at the Commission. In any event, the Commission anticipates that disputes over the appropriate level of transmission facility credits should not preclude transmission customers from initiating service under the tariff. Where the parties are unable to reach agreement on the appropriate credit for customer-owned transmission facilities, the parties may make an appropriate filing with the Commission.

g. Ceiling Rate for Non-Firm Point-to-Point Service

Comments
Commenters generally support a ceiling rate for non-firm transmission service, capped at the firm rate.[FN453] Others request clarification as to whether the point-to-point tariff rates are fixed or are ceiling rates. Central Illinois Public Service's major concern is that, if the rates are fixed, the tariffs may result in higher prices for capacity and energy than those currently allowed for bundled service.

NYSEG argues that unequal pricing is a natural phenomenon of the open marketplace and requests assurance that offering transmission service at prices below a cost-based ceiling rate will not expose a transmission provider to claims of undue discrimination.

AEC & SMEPA opposes using the firm rate as the cap for non-firm transmission service. It states that, given the substantially lower quality of non-firm service (with no obligation to plan for such service), no cost-of-service principle justifies charging rates for non-firm service as high as the rate for firm service.

EGA and NRECA state that any discounts from the maximum firm rate must be uniform, transparent, readily understood, and posted on a RIN. According to CCEM and NRECA, the transmitting utility must have nondiscriminatory discount practices and must contemporaneously offer discounts to transmission customers at the same time and on the same basis as discounts for internal sales operations or affiliates.

Commission Conclusion
We believe that it is important to continue to allow pricing flexibility. In accordance with the Commission's current policies, the rate for non-firm point-to-point transmission service may reflect opportunity costs. Any provisions for opportunity cost pricing for non-firm service must meet the requirements already discussed. If a utility chooses to adopt opportunity cost pricing, the non-firm rate is effectively capped by the availability of firm service and is not subject to a separately-stated price cap. If a utility chooses not to adopt opportunity cost pricing, the non-firm rate is capped at the firm rate. We also wish to ensure that non-firm transmission service is priced in a nondiscriminatory fashion. Accordingly, if a transmission provider offers a rate discount to its affiliate, or if the transmission provider attributes a discounted rate to its own transactions, the same discounted rate must also be offered at the same time to non-affiliates on the same transmission path and on all unconstrained transmission paths. We will further require that any affiliate discounts from the maximum firm rate must be transparent, readily understandable, and posted on the transmission provider's OASIS in advance so that all eligible customers have an equal opportunity to purchase non-firm transmission at the discounted rate.[FN454] In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory and must be reported on the OASIS within 24 hours of when available transmission capability (ATC) is adjusted in response to the transaction. As discussed in the RIN section, information, including the price for all non-firm transaction discounts, must be posted on the OASIS to ensure comparability.

2. Priority for Obtaining Service

Comments
The term "priority" is used in the comments in several senses. The intent of the comment depends on which kind of "priority" is intended. In general, there are comments about the order in which parties can obtain new service, which we call "reservation priority," and there are comments about the order in which parties lose service they already have, which we call "curtailment priority." Commenters may establish different reservation priorities for various services, such as network, off-system sales, firm, ability to reserve a portion of new transmission ***21604** capacity to be constructed, and so on. Curtailment priorities also differ with the type of service. However, many commenters assert that certain parties should or should not have "priority" without distinguishing the kind of priority or type of service for which priority is intended.

a. Reservation Priority for Existing Firm Service Customers

155 FERC ¶ 61,068
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Occidental Chemical Corporation | Docket No. EL13-41-000

v.

The Midwest Independent System Operator, Inc.

ORDER DENYING COMPLAINT

(Issued April 21, 2016)

1. On January 17, 2013, Occidental Chemical Corporation (Occidental) filed a complaint and petition for declaratory order (Complaint) against the Midwest Independent Transmission System Operator, Inc. (MISO).[1] Occidental requests that the Commission find that MISO's treatment of qualifying facilities (QF) in the Entergy[2]

[1] Effective April 26, 2013, MISO changed its name from "Midwest Independent Transmission System Operator, Inc." to "Midcontinent Independent System Operator, Inc."

[2] The Entergy Operating Companies are Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc. Below, we will refer to the Entergy Operating Companies collectively and also Entergy Services, Inc. (which has submitted filings in this proceeding on behalf of the Entergy Operating Companies) as "Entergy," unless necessary to distinguish between them. Entergy Gulf States, Louisiana, L.L.C. and its affiliate, Entergy Louisiana, LLC, concluded a transaction in which they combined substantially all of their respective assets and liabilities into a single successor public utility operating company, Entergy Louisiana Power, LLC, which subsequently was renamed Entergy Louisiana, LLC. The Commission authorized the transaction in *Entergy Gulf States Louisiana, L.L.C.*, 151 FERC ¶ 62,018 (2015), and Entergy Services, Inc. (Entergy Services) filed a notice of consummation in Docket

(continued ...)

between the Hybrid and Behind-the-Meter options to once per quarter, which is also consistent with MISO's business practices and its treatment of other resources, does not limit a QF's PURPA rights.

2. Hybrid QFs can maintain their PURPA rights with respect to curtailment priority

73. The Commission's PURPA regulations only permit curtailment of QF energy sales under limited circumstances, such as system emergencies.[136] A system emergency is a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.[137] Section 292.307(b) provides that a utility may, during a system emergency, discontinue purchases from a QF if such purchases would contribute to such an emergency. Accordingly, in *SPP*, the Commission allowed curtailment of QF generation during transmission loading relief level TLR-5, as defined by NERC, because TLR-5 events are akin to system emergencies triggering curtailment of QF generation under 18 C.F.R. § 292.307(b).[138] Occidental contends that, under the Hybrid option, QFs would lose their PURPA protection against curtailment when selling pursuant to PURPA. Here, in answer to Occidental, MISO has explained that there are steps that QFs can take to prevent their facilities from being dispatched down (i.e., effectively curtailed), except in the event of a system emergency. According to MISO, any generator may through its offer or operational characteristics designate its unit as nondispatchable. MISO states that it will not dispatch down any unit that is designated as nondispatchable. Additionally, we note, a Hybrid QF could self-schedule in MISO's Real-Time market. Self-scheduling would result in the QF being able to provide whatever level of energy it chooses and the QF would only be curtailed by manual action of MISO's system operators during a system emergency, on a nondiscriminatory basis.[139]

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[136] 18 C.F.R. § 292.307(b) (2015). Section 292.307(b) of the Commission's regulations provides that a utility may, during a system emergency, discontinue purchases from a QF if such purchases would contribute to such an emergency. Section 292.101(b)(4) of the Commission's regulations defines "system emergency" as a "condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." *Id.* § 292.101(b)(4).

[137] 18 C.F.R. § 292.101(b)(4) (2015).

[138] *Sw. Power Pool, Inc.*, 140 FERC ¶ 61,225, at P 51 (2012) (*SPP*).

[139] MISO, FERC Electric Tariff, §§ 33.7 (30.0.0), 33.8.1 (30.0.0). Additionally, a

(continued ...)

74. The Commission, therefore, finds that Hybrid QFs are able to maintain their PURPA rights with respect to curtailment priority when selling under PURPA.

3. MISO is not required to file the QF Integration Plan in its Tariff

75. According to Commission precedent, "[p]ractices that significantly affect rates, terms and conditions of service must be included in a Commission-approved tariff rather than in other documents."[140] That is, practices, policies and operating procedures of public utilities that "significantly affect rates and services" must be filed under section 205 of the FPA.[141] Contrary to the arguments advanced by protesters, we find that the material contained in the MISO QF Integration Plan and FAQ does not "significantly affect rates, terms and conditions of service."

76. Similar to MISO's Business Practice Manuals, the MISO QF Integration Plan and FAQ provide implementation details which guide internal operations and inform market participants of how MISO conducts operations under its Tariff.[142] Specifically, the MISO QF Integration Plan and FAQ provide additional detail for market participants regarding how existing Tariff mechanisms (e.g., financial schedules) apply to QFs. We find that additional tariff revisions are not necessary merely because these existing mechanisms are also used to facilitate sales pursuant to PURPA. Accordingly, we find that MISO should not be required to include the QF Integration Plan or FAQ in its Tariff.

4. MISO Imposition of Other Market Charges on Hybrid QFs

77. Occidental argues that MISO has unlawfully imposed Schedule 17 administration charges and Schedule 24 load balancing authority charges on Hybrid QFs using financial schedules. Specifically, Occidental argues that allowing MISO to directly assess Schedule 17 and Schedule 24 charges to Hybrid QFs is duplicative and additive to Other Market Charges already included in the avoided cost methodology adopted by the

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QF can self-commit its unit by designating the unit as "Must Run," which requires MISO to commit and dispatch the unit at the level of the self-commitment. Entergy June 5, 2014 Answer at 2-3; *See* MISO, FERC Electric Tariff § 39.2.5 (35.0.0).

[140] *Energy Spectrum, Inc. v. N.Y. Indep. Sys. Operator, Inc.*, 141 FERC ¶ 61,197 at P 51 & n.25.

[141] *Id.*

[142] *See Cal. Indep. Sys. Operator Corp.*, 122 FERC ¶ 61,271, at P 16 (2008).

Louisiana Commission, or that MISO's assessing Other Market Charges directly to Hybrid QFs otherwise violates their PURPA rights. We disagree.

78. The avoided cost methodology adopted by the Louisiana Commission includes Other Market Charges that are deducted from LMP.[143] For Behind-the-Meter QF PURPA puts, Entergy pays the QF the real time LMP at the applicable load zone after deducting Other Market Charges (i.e., including, but not limited to, Schedule 17 and Schedule 24 charges) related to the QF output that MISO assesses to Entergy. However, for Hybrid QF PURPA puts made to a utility using financial schedules, Entergy pays the Hybrid QF the LMP at the QF's generator bus and MISO would directly assess the QF the Other Market Charges associated with the QF output, the same as it would any other market participant.[144] In the end, the QF is financially in the same place for PURPA sales under the Hybrid option and for sales under the Behind-the-Meter option. Thus, unlike in *SPP* where the Commission found that Southwest Power Pool could not assess market charges because it would reduce the avoided cost received by QFs, here the record demonstrates that the avoided cost methodology approved by the Louisiana Commission deducts Other Market Charges as part of the formula.[145] MISO's assessment of Other Market Charges directly to Hybrid QFs thus does not reduce the avoided cost received by QFs.

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[143] *In re: Joint Application of Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC for Approval of the Modification of the Current Methodology for Calculating Avoided Cost*, Order No. U-32628-A (Louisiana Commission, issued Jan 9, 2014) at 7-8.

[144] *See* Occidental March 28, 2013 Answer, Attachment 1 (November 2012 Direct Testimony of John P. Hurstell, Errata No. 1 to LPSC Docket No. U-32628) at 29, lines 3-7 ("Any penalties charged by MISO based on puts from a Hybrid QF will be assessed directly to the generator, not the Companies. Hybrid QFs, however, can limit any such penalties by adhering to MISO's real time set points and putting the resulting energy.").

[145] *Id.*

A Network Customer's monthly Network Load is its hourly Load (60 minute, Hour); provided, however, the Network Customer's monthly Network Load will be its hourly Load coincident with the monthly peak of the pricing zone where the Network Customer's Load is physically located or as otherwise located as defined in Section 31.3 (b) or (c). A Network Customer's monthly Network Load shall exclude any withdrawals of Energy by Electric Storage Resources while providing Regulating Service or Down Ramp Capability.

Transmission losses refer to the loss of energy during the transmission of electricity from generation resources to Load, which is dissipated as heat through transformers, transmission lines, and other transmission facilities that are under the functional control of the Transmission Provider. When reporting monthly network coincident peak loads to MISO for billing purposes, load reporting entities will adjust Network Load to account for Transmission losses in accordance with MISO Business Practice Manual – 012.

Part 1 of 2

ORIGINAL

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FEDERAL ENERGY
REGULATORY COMMISSION

COMPLAINT REQUESTING FAST TRACK PROCESSING

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Occidental Chemical Corporation	)	
v.	)	Docket No. EL13- 41-000
Midwest Independent Transmission System Operator, Inc.	)	

PETITION FOR DECLARATORY ORDER AND COMPLAINT REQUESTING FAST TRACK PROCESSING OF OCCIDENTAL CHEMICAL CORPORATION AGAINST THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Daniel A. Hagan
Jane E. Rueger
Caileen N. Gamache
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Counsel for Occidental Chemical Corporation

January 17, 2013

385.203(a)(5) of Commission's regulations,[38] the Midwest ISO's address is: P.O. Box 4202; Carmel, IN 46082-4202.

Entergy has announced its intent to join the Midwest ISO.[39] If Entergy joins the Midwest ISO as planned, the Taft Facility and OCC's loads described above will be located within the Midwest ISO balancing authority area. The Midwest ISO has targeted integration of generators and loads in the Entergy footprint by December 18, 2013.[40]

On October 10, 2012, the Midwest ISO issued a document explaining its MISO QF Integration Plan, titled "Qualifying Facilities (QF) Generator Readiness for MISO Reliability Coordination and Market Integration" ("QF Readiness Document"), that "provides information for QFs transitioning into the MISO Reliability Coordination (RC) Area" and "information for QFs that desire to participate in MISO's Market Operations."[41] The QF Readiness Document is attached hereto as Attachment A. In pertinent part, the QF Readiness Document indicates that the Midwest ISO maintains a "Commercial Model" that is "used to manage and price transactions in the Energy, Operating Reserves, and Ancillary Services markets"[42] run by the Midwest ISO. Generators, including QFs, "must register for the Commercial Model if they want to sell energy, capacity, or ancillary services in the day-ahead or real-time MISO markets."[43] In furtherance of the December 18, 2013 integration date, the Midwest ISO has stated that

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38 18 C.F.R. § 385.203(a)(5).

39 *See Midwest Independent Transmission System Operator, Inc.*, Filing of *Pro Forma* Tariff Sheets Including Proposed Module B-1 to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff, Docket No. ER12-2682 (filed Sept. 24, 2012).

40 QF Readiness Document at 15.

41 *Id.* at 3.

42 *Id.* at 4.

43 *Id.*

Qualifying Facilities (QF) Generator Readiness for MISO Reliability Coordination and Market Integration

Prepared by MISO
10/10/2012

P.O. Box 4202
Carmel, IN 46082-4202
Tel: 317-249-5400
Fax: 317-249-5703

www.misoenergy.org

Requirement	Timeframe
If metering on the generator is needed per requirements detailed above / net metering is insufficient)	ASAP
Telemetry (Utilize existing or install communication system with Entergy Systems Operation Center (SOC) or in certain circumstances install WAN equipment for ICCP communication directly with MISO) • **If a Generator seeks to install WAN equipment for a direct ICCP connection to MISO, the Generator is required to cover the purchase of the equipment, at an approximate cost of $8,000, and pay a monthly fee of up to $1,500 for the high speed phone line.**	ASAP if no existing communication with SOC to either SOC or MISO
One line Diagram information must be incorporated into the MISO network Model (direct submittal to MISO preferred)	ASAP
Generator Outages >10 MW must be reported into MISO's Outage Coordination System CROW (via Entergy Systems Operation Center (SOC) or in certain circumstances directly with MISO)	ASAP

The table below provides a summary of the requirements and impacts of the Entergy Operating Company's and the QF's activities by various MISO functions.

MISO Function	Requirement/Impact
Reliability Coordination (Monitoring)	• Requires explicit modeling of generators and LBA loads. • Real-time metering is required to provide ICCP/SCADA information. • Applies to >80 MVA QFs connected at >=69 KV, whether behind the meter or Hybrid.
Commercial Model	• The Entergy Operating Company would be the Market Participant for BTM QFs, while the QF or its agent would be the MP for Hybrid QFs. • Net output would be aggregated into a Load Zone CPNode for BTM QFs and into a Gen CPNode for Hybrid QFs. • Revenue quality metering is required. • Load would remain as Retail.
Auction Revenue Rights/Financial Transmission Rights	• Load associated with a QF would only be eligible for an allocation of ARRs to the extent it has Transmission Service that qualifies for such an allocation under MISO's tariff.
Day-Ahead Market	• The Day-Ahead Market cannot receive offers for surplus BTM generation (negative MW bids are not allowed for a Load Asset) • Hybrid QFs can submit offers and/or self-schedule for their surplus Gen-to-Market. • Virtual Bids could be used to hedge Day Ahead vs. Real-Time prices. Please refer to the MISO Credit Policy for virtual activity market rules.
Real-Time Market	• Hybrid QFs can submit offers and/or self-schedules for their surplus Gen-to-Market. • When the CPNode has net injections or withdrawals in comparison to its Day Ahead Schedule, it is a price taker and will receive appropriate imbalance charges.
Transmission Service	• The applicable Entergy Operating Company, as the Load Serving Entity, would need to designate the net withdrawals as a Network Load

MISO Function	Requirement/Impact
	• QF would settle with Entergy directly per the appropriate Entergy Operating Company Retail Tariff requirements.
Market Settlements	• The applicable Entergy Operating Company, as the Load Serving Entity, would be responsible for all market charges and they would be settled at the CPNode that includes the QF generation and load. • QF would settle with Entergy directly per the appropriate Entergy Operating Company Retail Tariff requirements.
Transmission Settlements	• The applicable Entergy Operating Company, as the Load Serving Entity for the QF load, would pay for Network Service for the net withdrawal
Interconnection Service	• If the QF's are tied to an Entergy Operating Company's transmission facilities placed under the MISO Tariff then all QF uprates and/or retirements would need to go through the MISO processes.

Appendix B: Behind the Meter and Hybrid Configuration Examples

The following diagrams illustrate how the Behind the meter and "hybrid" approaches discussed above will be modeled. Please note QFs participating in the hybrid will have to provide revenue quality meter data that reflect their operations and net injections into the MISO market for settlement purposes.

All generation participating in the Day-Ahead or Real-Time Market are subject to the following:

- Changes to Commercial model arrangements can be made on a quarterly basis per MISO modeling practices
- Generator parameters can be changed on an hourly basis per market operations practices
- Generators participating in the Day-Ahead market will be required to follow Real-Time dispatch instructions
- Generators participating in the Real-Time market will receive four second dispatch, ancillary clearing and setpoint instructions. See Section 6.9 of Balancing Authority Functional Alignment and Ancillary Service Market Implementation ICCP Data Exchange Specification."

§25.239. Transmission Cost Recovery Factor for Certain Electric Utilities.

(a) **Application.** The provisions of this section apply to an electric utility that operates solely outside of the Electric Reliability Council of Texas in areas of Texas included in the Southwest Power Pool or the Western Electricity Coordinating Council and that owns or operates transmission facilities.

(b) **Definitions.**

(1) **Approved transmission charges (ATC)** — Wholesale transmission charges approved by a federal regulatory authority that are not being recovered through the electric utility's other retail or wholesale rates and that are appropriately allocated to Texas retail customers. The charges may relate to the use of transmission facilities owned and operated by another transmission service provider or regional transmission organization, including transmission-related administrative fees but not including dispatch fees, congestion charges, costs incurred to hedge congestion charges, or ancillary service charges.

(2) **Transmission invested costs (TIC)** — The net change in the electric utility's transmission investment costs including additions, upgrades, and retirements as booked in FERC accounts 350-359, and accumulated depreciation.

(c) **Recovery authorized.** The commission, after notice and hearing, may allow an electric utility to recover its reasonable and necessary costs for transmission infrastructure improvement and changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority to the extent that the costs or charges have not otherwise been recovered and are incurred after December 31, 2005. Any such recovery shall be made through the use of a transmission cost recovery factor (TCRF) approved by an order of the commission. The TCRF shall be calculated pursuant to subsection (d) of this section. If a utility has not had a base rate case with a final order issued after December 2005, the utility shall not be eligible for recovery under this provision without first obtaining a final order in a base rate case.

(d) **Transmission cost recovery factor (TCRF).** The TCRF shall be determined by the following formula:

$$\text{TCRF} = \frac{RR * ClassALLOC}{BD}$$

Where:	TCRF = transmission cost recovery factor in dollars per unit, for billing each customer class.
	RR = transmission cost recovery factor revenue requirement, calculated pursuant to subsection (e) of this section.
	ClassALLOC = the customer class allocation factor used to allocate the transmission revenue requirement in the utility's most recent base rate case.
	BD = each customer class's annual billing determinant (kilowatt-hour, kilowatt, or kilovolt-ampere) for the previous calendar year.

(e) **Transmission cost recovery factor revenue requirement (RR).** For an electric utility subject to this section, the transmission cost recovery factor revenue requirement (RR) shall be calculated by using the following formula:

RR = [revreqt + ATC]*ALLOC	
Where:	Revreqt = the sum of the return on TIC, net of accumulated depreciation and associated accumulated deferred income taxes, plus investment-related expenses such as income taxes, other associated taxes, depreciation, and transmission–related miscellaneous revenue credits, but not including operation and maintenance expenses or administrative expenses. The return on TIC shall be calculated by multiplying the TIC by the utility's weighted-average cost of capital (WACC) as established for the utility in a final commission order in a base rate case, provided that the order was filed within three years prior to the initiation of the TCRF docket. Otherwise, a proxy WACC shall be used, with a cost of equity of 10%; and the capital structure and cost of debt as reported in the utility's most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports), adjusted for known and measurable changes.
	Transmission Invested Costs (TIC) is defined in subsection (b)(2) of this section.
	Approved Transmission Charges (ATC) is defined in subsection (b)(1) of this section.
	ALLOC = the utility's Texas retail allocation of transmission revenue requirements, as established in the utility's most recent base rate case.

(f) **Setting and amending the TCRF.** An electric utility that is subject to this section may file an application to set or amend a TCRF. The commission staff may also file an application to amend a TCRF. An electric utility may not apply to amend its TCRF more frequently than once each calendar year, but a TCRF shall be reviewed or amended at least once every three years. Upon completion of a base rate case for a utility, the TCRF shall be set to zero. In a docket in which the TCRF is reviewed or amended, the commission may order the refund of any previous over-recovery, but the commission shall not order the surcharge of any under-recovery. An over-recovery shall be considered to have occurred if the revenues from the TCRF were greater than the costs that the TCRF was intended to recover.

(g) **TCRF forms.** The commission may develop forms for TCRF applications and for monitoring the revenues from a TCRF. If the commission develops and approves such forms, an electric utility shall use the forms as required by the instructions accompanying the form.

SPP Southwest Power Pool

Revision Request Recommendation Report

RR #: 241	**Date:** 8/31/2017
RR Title: MOPC Policy on Determination of Network Load	
SUBMITTER INFORMATION	
Name: Matt Harward, on behalf of the RTWG	**Company:** SPP, on behalf of the RTWG
Email: mharward@spp.org	**Phone:** (501) 614-3560
EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION	
The RTWG recommends that the MOPC and the BOD approve RR 241 as submitted in this recommendation report.	
OBJECTIVE OF REVISION	

Objectives of Revision Request:
Describe the problem/issue this revision request will resolve

RTWG to develop Tariff language that implements following policy adopted at the July 2017 MOPC meeting: **Any generation in front of a retail meter be included. Any generation behind a retail meter greater than 1 MW shall also be included.**

Describe the benefits that will be realized from this revision

At the July 2017 MOPC meeting, the RTWG requested that if the MOPC would like the RTWG to continue its efforts to develop Tariff language to address the Behind-the-Meter/Network Load issue that the MOPC settle the policy debate over the resource's MW threshold for load exclusions and any other resource inclusions/exclusions from Network Load. *See* 2017 MOPC Meeting Minutes at Agenda Item 7.

The benefit of this revision request will be satisfaction of the MOPC direction for the RTWG to develop Tariff language to address the determination of Network Load based on its policy as it pertains to inclusion/exclusions of generation units that are located on the load side of a discrete delivery point identified in a network customer's service agreement.

SPP STAFF ASSESSMENT

SPP staff supports the changes proposed in RR 241.

IMPACT

Will the revision result in system changes ☒ **No** ☐ **Yes**

Summarize changes:

Will the revision result in process changes? ☒ **No** ☐ **Yes**

Summarize changes:

Is an Impact Assessment required? ☒ **No** ☐ **Yes**

If no, explain:

Estimated Cost: $	**Estimated Duration:** months
Primary Working Group Score/Priority:	

SPP DOCUMENTS IMPACTED

☐ **Market Protocols**	**Protocol Section(s):**	**Protocol Version:**

☐ **Operating Criteria**	**Criteria Section(s):**	**Criteria Date:**
☐ **Planning Criteria**	**Criteria Section(s):**	**Criteria Date:**
☒ **Tariff**	**Tariff Section(s):** 34.4	
☐ **Business Practice**	**Business Practice Number:**	

WORKING GROUP REVIEWS AND RECOMMENDATIONS

List Primary and any Secondary/Impacted WG Recommendations as appropriate

Primary Working Group: **RTWG**	**Date:** 9/28/2017 **Action Taken:** To approve that the RR as modified implements the intent of the MOPC policy direction **Abstained:** NextEra, OMPA **Opposed:** NPPD, Tenaska

Reason for Opposition:

NPPD: NPPD voted "no" because the language should have included as an exclusion from the calculation of network load: A generator of an individual retail customer located behind the retail meter where the output of such generator is owned and controlled by the retail customer and is generally intended to be consumed only by that retail customer on the retail customer's site.

NPPD believes that this language has the same intent of PJM's tariff language that was approved by FERC (Docket No. ER04-608-002). Under PJM's current definition, BTM generation consists of "units that are located with load at a single electrical location such that no transmission or distribution facilities are used to deliver energy from the generating unit to the load."

A large portion of NPPD's business model is to supply power to wholesale customers and NPPD feels RR 241 reaches too far to the retail customer that NPPD doesn't control.

Tenaska: I have voted no on RR241 at RTWG because it doesn't take the way QF's with self-serve load operate and that some load will go away when the generation goes away.

Reason for Abstaining:

OMPA: My abstention yesterday was based on the fact that OMPA would like to see a limit on the amount of generation that should be included in load, specifically between a delivery point meter and a retail meter. Tracking and metering small DG projects (ie: city installs a demonstration solar project) would be burdensome and have little to no impact on network load.

MOPC	**Date:** 10/17/2017 **Action Taken:** Rejected **Abstained:** **Opposed:**

Reasons for Opposition:

BOD/Member Committee	**Date:** **Action Taken:** **Abstained:** **Opposed:**

Reasons for Opposition:

COMMENTS

Comment Author: John Weber/Missouri River Energy Services

Date Comments Submitted: 9/14/2017
Description of Comments: MRES appreciates the opportunity to provide comments to this revision request. Although we believe the revision is a step in the right direction, more detail is needed to avoid ambiguity and to prevent gaming of these clarified rules. 1. Item 34.4 B. 1. is a new definition for the term "Discrete Delivery Point" and should be added to the definitions section of the tariff and should not be defined solely for this section. This will avoid potentially conflicting definitions throughout the Tariff and provides for a less cluttered Tariff overall. 2. The revision needs to clarify the logic for each of the new conditions such as which conditions should be read as "and" and which ones should be read as "or". For example, a generator could be in front of a retail customer meter (as in condition 2) "or" behind a retail customer meter (as in condition 3) thus conditions 2 & 3 are "or" statements to each other, whereas condition 4 would apply to both condition 2 "and" condition 3 thus is an "and" statement to the others. Condition 5 appears to only be applicable to condition 3, or at least it only makes sense when applied to condition 3. 3. Condition 3 should be clarified to include the summation of all generation behind an individual retail meter, and not pertain to any single unit needing to be over 1 MW before it is included. Also, the generation nameplate should be the reference for the limit as to avoid potential gaming of the size of a unit. See suggested language below. 4. Emergency back-up needs to be defined such that it is clear the emergency unit only runs to prevent the loss of a specific load and cannot be operated for power supply, economic, or transmission costs related issues.
Status: Comments were considered by the RTWG
COMMENTS
Comment Author: Alex Dobson/Oklahoma Municipal Power Authority
Date Comments Submitted: 9/14/2017
Description of Comments: OMPA would like to propose an edit to section 2 of RR241 for the following reasons: - Make section 2 consistent with section 3. - Eliminate the burden of metering or tracking generators under 1MW that are not behind a retail meter. - Establish a limit for clarity and allow for aggregated generators up to 1MW on a single delivery point that are not behind a retail meter.
Status: Comments were considered by the RTWG
COMMENTS
Comment Author: Robert Pick/NPPD
Date Comments Submitted: 9/19/2017
Description of Comments: 1. Exclude: Load served by the generator or combination of generators is automatically reduced in an equivalent amount to the output of the generator(s) upon the loss of the generator(s). 2. A reasonable size threshold (1 MW) for exclusion should be included in section B.2 similar to how it is included in section B.3. Other Items to be considered in future RR's of entities not taking network service or SPP point-to-point 3. How will a generator (i.e. wind generation) that doesn't take SPP network service or SPP point-to- point service be reported or captured? 4. How will generation that offsets load that doesn't take SPP network service or SPP point to point service reports the load?

Status: Comments were considered by the RTWG
COMMENTS
Comment Author: Golden Spread Electric Cooperative, Inc.
Date Comments Submitted: 9/25/2017
Description of Comments: Golden Spread appreciates the opportunity to comment on such an important issue. Golden Spread believes it imperative that SPP clarify the treatment of generators behind the wholesale delivery points in the Network Load calculation. Differences among the application of this requirement across the SPP can result in disparate results to Network Customers whose load ratio share calculation is premised on the determination of its own Network Load in relation to total Network Load. For the reasons below, Golden Spread urges the SPP to adopt the following changes to RR 241: 1) Golden Spread believes that any exemption to the Network Load calculation should be applied in a non-discriminatory manner to all generators behind the Discrete Delivery Point, regardless of ownership. If, for example, 1 MW is an appropriate de minimis cut-off for generation behind a retail meter, then why does it matter who owns the generation? The proposed language appears to unreasonably discriminate against Network Customers that own generation and could have unintended consequences. OATT principles dating back to Order Nos. 888, 890 and 2003 require that all transmission customers and generators should be treated in a non-discriminatory manner and any other treatment may be inconsistent with these principles. Additionally, the guidance adopted at the July 2017 MOPC meeting applies to "any generation" and does not make a distinction between ownership. Golden Spread believes that applying the language solely to Network Customer's generation is not only discriminatory and inconsistent with FERC's guiding open access principles, but also inconsistent with the policy adopted by at the July 2017 meeting. 2) Golden Spread believes that a 1 MW de minimis exemption makes the most sense for behind the retail meter generation, however, it should be applied aggregately. That is, the de minimis threshold would be exceeded when the sum of all behind the retail meter generation, behind a Discrete Delivery Point, exceeds 1 MW. Golden Spread opposes the 1 MW exemption applied on a per retail meter basis because it could result in the undesirable consequence of pushing greater transmission costs onto Network Customers with less distributed generation, causing a significant "free rider" issue that is inconsistent with cost causation. It could also incentivize increased distributed generation behind the retail meter for the sole purpose of avoiding or reducing transmission costs, leading to a "race to the bottom". At the same time, these customers would enjoy the same high level of service that network integration transmission service provides. There is no justification for this outcome, particularly at this juncture, when the role of electric utilities to integrate distributed resources is predicted to grow substantially and preference to particular resource types through special exemptions from transmission cost responsibility should not be baked into special rules for transmission cost responsibility. As DG penetration grows, such a special exemption has serious implications for transmission cost allocation in the long run. 3) Interval meters may be cost prohibitive for smaller systems. For this reason, Golden Spread believes that the use of name plate capacity, should be allowed as an option.
Status: Comments were considered by the RTWG
PROPOSED REVISION(S) TO SPP DOCUMENTS
Tariff (OATT)

Determination of Network Customer's Monthly Network Load:

A. Network Load Calculation

The Network Customer's monthly Network Load is its hourly load (60 minute, clock-hour); provided, however, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone where the Network Customer load is physically located. Where a Network Customer has Network Load in more than one Zone, the monthly Network Load will be determined separately for each Zone. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.4, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone that is the basis for charges under Schedule 9.

B. Special Rules Governing Inclusion of Generation Units Located on the Load Side of a Discrete Delivery Point

1. For purposes of this Section 34.4.B, the term Discrete Delivery Point shall be defined as the delivery points identified in Appendix 3 of the Network Customer's Network Integration Transmission Service Agreement.

2. The output from a generation unit(s) located behind the meter at a Discrete Delivery Point and in front of a retail end-use customer's meter shall be included in the determination of a Network Customer's monthly Network Load.

3. The output from a generation unit with a nameplate rating greater than 1.0 MW, or the sum of the output from generation units with a combined nameplate rating greater than 1.0 MW, located behind a retail end-use customer's meter shall be included in the Network Customer's determination of monthly Network Load.

4. If billing meter data of a generation unit is not available during times when the generation unit was online, the Network Customer shall use the nameplate rating as the output in calculating the Network Load at the Discrete Delivery Point.

45. A generation unit located behind a retail end-use customer's meter that is utilized for emergency back-up operations and is not synchronized to run parallel with the Transmission System shall be excluded from the Network Customer's determination of monthly Network Load.

Market Protocols

N/A

SPP Operating Criteria

N/A

SPP Planning Criteria

N/A

SPP Business Practices

N/A

occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.305 Rates for sales.

(a) *General rules.* (1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional services to be provided to qualifying facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

§ 292.306 Interconnection costs.

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

§ 292.307 System emergencies.

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.308 Standards for operating reliability.

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure

§25.242. Arrangements Between Qualifying Facilities and Electric Utilities.

(a) **Purpose.** The purpose of this section is to regulate the arrangements between qualifying facilities, retail electric providers with the price to beat obligation (PTB REPs), and electric utilities as required by federal and state law in a manner consistent with the development of a competitive wholesale power market.

(b) **Application.** This section applies to all PTB REPs and to all electric utilities, including transmission and distribution utilities. The provisions of this section concerning purchase or sale of electricity between an electric utility and a qualifying facility do not apply to a transmission and distribution utility. This section does not apply to municipal utilities, river authorities, or electric cooperatives.

(c) **Definitions.** The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) **Avoided costs** -- The incremental costs to a PTB REP, or electric utility of electric energy, which, but for the purchase from the qualifying facility or qualifying facilities, such PTB REP or electric utility would generate itself or purchase from another source.

(2) **Back-up power** -- Electric energy or capacity supplied to replace energy or capacity ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the qualifying facility.

(3) **Cost of decremental energy** -- The cost savings to a utility associated with the utility's ability to back-down some of its units or to avoid firing units, or to avoid purchases of power from another source because of purchases of power from qualifying facilities.

(4) **Electric utility** -- For purposes of this section, an integrated investor-owned utility that has not unbundled in accordance with Public Utility Regulatory Act §39.051.

(5) **Firm power** -- From a qualifying facility, power or power-producing capacity that is available pursuant to a legally enforceable obligation for scheduled availability over a specified term.

(6) **Host utility** -- The utility with which the qualifying facility is directly interconnected.

(7) **Maintenance power** -- Electric energy or capacity supplied during scheduled outages of the qualifying facility.

(8) **Market price** -- The market-clearing price of energy (MCPE) in the balancing energy market for the Electric Reliability Council of Texas (ERCOT) congestion zone in which the power is produced, minus any administrative costs, including an appropriate share of ERCOT-assessed penalties and fees typically applied to power generators.

(9) **Non-firm power from a qualifying facility** -- Power provided under an arrangement that does not guarantee scheduled availability, but instead provides for delivery as available.

(10) **Parallel operation** -- A mode of operation which enables a qualifying facility to export automatically any electric capacity which is not consumed by the qualifying facility or the user of the qualifying facility's output. Parallel operation results in three possible states of operation at any point in time:

(A) The qualifying facility is generating an amount of capacity that is less than the customer's load. The customer is therefore a net consumer.

(B) The qualifying facility is generating an amount of capacity that is more than the customer's load. The customer is therefore a net producer.

(C) The qualifying facility is generating an amount of capacity that is equal to the customer's load. The customer is therefore neither a net producer nor a net consumer.

(11) **Purchase** -- The purchase of electric energy or capacity or both from a qualifying facility by a PTB REP or electric utility.

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(12) **Purchasing utility** -- The electric utility that is purchasing a qualifying facility's capacity and/or energy.

(13) **Quality of firmness of a qualifying facility's power** -- The degree to which the capacity offered by the qualifying facility is an equivalent quality substitute for firm purchased power or an electric utility's own generation. At a minimum the following factors should be considered in determining quality of firmness:

(A) reliability of generation and interconnection;

(B) forced outage rate;

(C) availability during peak periods;

(D) the terms of any contract or other legally enforceable obligation, including, but not limited to, the duration of the obligation, performance guarantees, termination notice requirements, and sanctions for noncompliance;

(E) maintenance scheduling;

(F) availability for system emergencies, including the ability to separate the qualifying facility's load from its generation;

(G) the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system;

(H) other dispatch characteristics;

(I) reliability of primary and secondary fuel supplies used by the qualifying facility; and

(J) impact on utility system stability.

(14) **Retail electric provider with the price to beat obligation (PTB REP)** -- A REP that makes available a PTB pursuant to PURA §39.202.

(15) **Sale** -- The sale of electric energy or capacity or both supplied to a qualifying facility.

(16) **Supplementary power** -- Electric energy or capacity regularly used by a qualifying facility in addition to that which the facility generates itself.

(17) **System emergency** -- A condition on a utility's system that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(18) **Transmission and distribution utility (TDU)** -- As defined in §25.5 of this title (relating to Definitions).

(d) **Negotiation and filing of rates.**

(1) **Negotiated rates or terms.** Nothing in this section shall:

(A) limit the authority of any PTB REP or electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differs from the rate or terms or conditions that would otherwise be required by this section; or

(B) affect the validity of any contract entered into between a qualifying facility and a PTB REP or electric utility for any purchase before the adoption of this section.

(2) **Filing of rates.** All rates for sales to qualifying facilities, contractual or otherwise, shall be contained in the schedule of rates of the electric utility filed with the commission.

(e) **Availability of electric utility system cost data.**

(1) **Applicability.** Paragraph (2) of this subsection applies to large electric utilities whose total sales of electric energy for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. Paragraph (3) of this subsection applies to all other electric utilities.

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(2) **Data request for large electric utilities.** Large utilities shall file the following data:

(A) the estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of one, ten and 100 megawatts or not more than 10% of the system peak demand for systems of less than 1,000 megawatts. The avoided cost shall be stated on a cents-per-kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next nine years.

(B) the electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding nine years.

(C) for the current year and each of the next nine years, the estimated capacity costs at completion of the planned capacity additions and planned capacity purchases, on the basis of dollars-per-kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases. Such information shall be submitted in accordance with the Federal Energy Regulatory Commission Regulations, 18 Code of Federal Regulations, §292.302 and shall be sufficient for qualifying facilities to reasonably estimate the utility's avoided cost. Accompanying each filing pursuant to this rule shall be a detailed explanation of how the data was determined, including sources and assumptions employed.

(3) Special requirements for small electric utilities. Affected utilities shall, upon request:

(A) provide to an interested person comparable data to that required under paragraph (2) of this subsection to enable qualifying facilities to estimate the electric utility's avoided costs; or

(B) with regard to an electric utility that is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide to an interested person the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(4) **Filing date.** By February 15 each year, large electric utilities shall file with the commission and shall maintain for public inspection the data set forth in paragraph (2) of this subsection.

(f) **PTB REP and electric utility obligations.**

(1) Obligation to purchase from qualifying facilities.

(A) In accordance with this subsection and subsection (g) of this section, each PTB REP and electric utility shall purchase any energy that is made available from a qualifying facility:

(i) directly to the PTB REP or electric utility; or

(ii) indirectly to the PTB REP or electric utility in accordance with paragraph (4) of this subsection.

(B) Each electric utility shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within 90 days of being notified by the qualifying facility that such energy is or will be available, provided that the electric utility has sufficient interconnection facilities available. If an agreement to purchase energy is not reached within 90 days after the qualifying facility provides such notification, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the 90th day following such notice. If the electric utility determines that adequate interconnection facilities are not