DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket Nos. RM95–8–001 and RM94–7–002; Order No. 888–A]

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

Issued March 4, 1997.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule; order on rehearing.

SUMMARY: The Federal Energy Regulatory Commission (Commission) reaffirms its basic determinations in Order No. 888 and clarifies certain terms. Order No. 888 requires 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. Order No. 888 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 rule is effective on May 13, 1997.

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I. Introduction and Summary

On April 24, 1996, the Commission issued Final Rules (Order Nos. 888 and 889) intended to remedy undue discrimination in the provision of interstate transmission services by public utilities and to address the stranded costs that may result from the transition to more competitive electricity markets.[1]

> At the heart of these rules is a requirement that prohibits owners and operators of monopoly transmission facilities from denying transmission access, or offering only inferior access, to other power suppliers in order to favor the monopolists' own generation and increase monopoly profits—at the expense of the nation's electricity consumers and the economy as a whole.

The electric utility industry today is not the industry of ten years ago, or even five years ago. While historically it was assumed that local utilities would be the only ones to generate and transmit power for their customers, today there is a broad array of potential competitors to supply power and widespread transmission facilities that can carry power vast distances. But competitors cannot reach customers if they cannot have fair access to the transmission wires necessary to reach those customers. It is against this industry backdrop that the Commission in Order No. 888 exercised its public interest responsibilities pursuant to sections 205 and 206 of the Federal Power Act (FPA), to reexamine undue discrimination in interstate transmission services and the effect of that discrimination on the electricity customers whom we are bound to protect under the FPA.

We here reaffirm the legal and policy bases on which Order No. 888 is grounded. Utility practices that were acceptable in past years, if permitted to continue, will smother the fledgling competition in electricity markets and undermine the national policies reflected in the Energy Policy Act of 1992 to encourage the development of competitive markets. We firmly believe that our authorities under the FPA not only permit us to adapt to changing economic realities in the electric industry, but also require us to do so, as necessary to eliminate undue discrimination and protect electricity customers. The record supports our conclusion that, absent open access, undue discrimination will continue to be a fact of life in today's and tomorrow's electric power markets. As recent events clearly demonstrate, unbundled electric transmission service will be the centerpiece of a freely traded commodity market in electricity in which wholesale customers can shop for competitively-priced power.

[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.

The only way to effectuate competitive markets and remedy discrimination is through readily available, non-discriminatory transmission access. The Commission estimates the potential quantitative benefits from such access will be approximately $3.8 to $5.4 billion per year in cost savings, in addition to the non-quantifiable benefits that include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion.

Order No. 888 has two central components. The first requires all public utilities that own, operate or control interstate transmission facilities to offer network and point-to-point transmission services (and ancillary services) to all eligible buyers and sellers in wholesale bulk power markets, and to take transmission service for their own uses under the same rates, terms and conditions offered to others. In other words, it requires non-discriminatory (comparable) treatment for all eligible users of the monopolists' transmission facilities. The non-discriminatory services required by Order No. 888, known as open access services, are reflected in a pro forma open access tariff contained in the Rule. The Rule also requires functional separation of the utilities' transmission and power marketing functions (also referred to as functional unbundling) and the adoption of an electric transmission system information network.

The second central component of Order No. 888 was to address whether and how utilities will be able to recover costs that could become stranded when wholesale customers use the open access tariffs, or FPA section 211 tariffs,[2] to leave their utilities' power supply systems and shop for power elsewhere. Because of competitive changes occurring at the retail level, as numerous states have begun retail transmission access programs, Order No. 888 also clarifies whether and when the Commission may address stranded costs caused by retail wheeling and the extent of the Commission's jurisdiction over unbundled retail transmission. The Commission further addresses the circumstances under which utilities and their wholesale customers may seek to modify contracts made under the old regulatory regime, taking into account the goals of reasonably accelerating customers' ability to benefit from competitively priced power and at the same time ensuring the financial stability of electric utilities during the transition to competition.

137 entities filed requests for rehearing and/or clarification of Order No. 888. While these parties raise a variety of arguments—including legal, policy, and technical arguments—the majority (including a majority of public utilities) agree that we need to harness the benefits that competitive electricity markets can bring to the nation. The disagreements primarily focus on the mechanics of how we should do this, who should pay the costs of the transition to competition, and how long the transition should take.

First, parties disagree on what is necessary to remedy undue discrimination and to develop truly competitive wholesale markets. Many focus specifically on the tariff terms and conditions of good transmission access and seek changes in the Order No. 888 pro forma tariff. In response to these types of rehearing arguments, the Commission has fine-tuned or changed some of the pro forma tariff terms and conditions to better ensure that they do not permit discrimination and that they result in well-functioning markets. Other petitioners focus on additional structural changes which they believe are necessary, such as mandatory corporate restructuring (divestiture of generation assets) or mandatory creation of independent transmission system operators (ISOs). With regard to restructuring, the Commission continues to believe that functional unbundling of the utility's business, not corporate divestiture or mandatory ISOs, is sufficient to remedy undue discrimination at this time.

The most contentious arguments raised on rehearing involve how we deal with the transition costs associated with moving to competition. Some utilities have invested millions of dollars in facilities and purchased power contracts based on an explicit or implicit obligation to serve customers and the expectation that those customers would remain on their systems for the foreseeable future. These utilities face so-called ''stranded costs'' which, if not recovered from the customers that caused the costs to be incurred, could be shifted to other customers.

There are two basic categories of rehearing arguments regarding stranded cost recovery. Most utilities want a guarantee from this Commission that they will recover all stranded costs, whether caused by losing retail customers or wholesale customers. Many customers, on the other hand, want to be able to abrogate existing power supply contracts so that they can immediately leave their current suppliers' systems and shop for cheaper power elsewhere, without paying the sunk costs that their suppliers incurred on their behalf.

In response to these diverse arguments, the Commission has struck a reasonable balance that, for certain defined circumstances, permits utilities the *opportunity* to seek extra-contractual recovery of stranded costs from their departing customers and permits customers the *opportunity* to make a showing that their contracts should be shortened or terminated. Based on our experience in the natural gas area, we have learned that it is critical to address these issues early, but we also have chosen an approach different from that taken in the gas area because of the different circumstances facing the electric industry.

In balancing the wide array of interests reflected in the rehearing petitions, we have made a number of clarifications and granted rehearing on some issues, but we reaffirm the core elements and framework of Order No. 888. Since the time the final rules issued, as discussed in Section III, the pace of competitive change has continued to escalate in the industry at both the wholesale and retail levels as competitors, customers and state regulatory authorities aggressively seek ways to lower the price of electricity. We therefore believe it is all the more critical that we remedy undue discrimination in interstate transmission services now, and that we do so generically, if we are to fulfill our responsibilities under the FPA to protect consumers and provide a fair and orderly transition to new competitive markets.

Finally, with respect to environmental issues associated with this rulemaking, certain parties on rehearing continue to challenge the adequacy of our Final Environmental Impact Statement (FEIS). The central issues are whether the Final Rule will increase emissions of nitrogen oxides (NOx) from certain fossil-fuel fired generators, which could affect air quality in downwind areas to which these emissions may be carried, and the Commission's authority to mitigate environmental consequences.

We deny rehearing on the environmental issues raised and affirm our conclusion that we have satisfied our obligations under NEPA. As discussed in detail in the Final Rule, this rulemaking is expected to slightly increase or slightly decrease total future

[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.

NOx emissions, depending on whether competitive conditions in the electric industry favor the utilization of natural gas or coal as a fuel for the generation of electricity. We also examined mitigation options over the longer term, and found that the preferred approach for mitigating any adverse environmental consequences would be for the Environmental Protection Agency (EPA) and the states to address the problem through regulatory authorities available under the Clean Air Act. The petitions for rehearing have not persuaded us to change this approach. Indeed, we note that since the issuance of Order No. 888, the EPA has concluded that the Rule is unlikely to have any immediate significant adverse environmental impact and thus concurred that the Commission's analysis is adequate under NEPA. We further note that EPA has recently taken steps under the Clean Air Act to address NOx emissions as part of a comprehensive emissions control program, along the lines endorsed by the Commission in the EIS.

In summary, the Commission believes that our authorities under the FPA not only permit us to adapt to changing economic realities in the electric industry, but also require us to do so to eliminate undue discrimination and protect electricity customers. The measures required in Order No. 888 are necessary to remedy undue discrimination in interstate transmission services and provide an orderly and fair transition to competitive bulk power markets.

To assist the reader, we provide below a section-by-section summary of key elements of this Order on Rehearing.

Scope of the Rule

In this section we discuss petitions to rehear our requirement that transmission and power sales services be contracted for separately (unbundled). We reaffirm that this requirement is a reasonable and workable means of assuring non-discriminatory open access transmission. In doing so we refuse invitations to require that utilities under our jurisdiction divest themselves of generation or transmission assets. We do, however, make an important clarification involving how we will deal with existing contracts that contain so-called *Mobile-Sierra* clauses (clauses under which one or both parties agreed not to seek modification of contract terms unless they could show that it is contrary to the public interest not to permit the modification).

In Order No. 888 we concluded that contracts would not be abrogated by operation of the Rule. Instead, preexisting contracts would continue to be honored until such time as they were revised or terminated. We also found that those who were operating under pre-existing requirements contracts containing *Mobile-Sierra* clauses would nonetheless be allowed to seek reform of the contracts on a case-by-case basis. On rehearing we affirm that public utilities will be allowed to file to amend their *Mobile-Sierra* contracts for the limited purpose of providing an opportunity to seek recovery of stranded costs, without having to make a public interest showing that such cost recovery should be permitted. However, these utilities will have the burden, on a case-by-case basis, of showing that they had a reasonable expectation of continuing to serve the departing customer after the contract term. We clarify that if the utilities under such contracts seek to modify provisions that do *not* relate to stranded costs, they will have the burden of showing that the provisions are contrary to the public interest.

We here make clear that, in turn, customers will be allowed to file to amend their *Mobile-Sierra* contracts to modify any contract term or to terminate the contract, without having to make a showing that the contract terms are contrary to the public interest. Instead, customers seeking modifications must demonstrate that the provisions they wish modified are no longer ''just and reasonable.'' We reaffirm our conclusion in the Final Rule that if a customer seeks to shorten or eliminate the term of its contract, however, any contract modification approved by the Commission will provide for appropriate stranded cost recovery by the customer's supplying utility.

These various provisions meet the two-fold need to deal with stranded costs and the contracts under which those costs were incurred. However, as described in Order No. 888, the opportunity to reform *Mobile-Sierra* contracts extends only to a limited set of contracts—those entered into on or before July 11, 1994, for requirements power.

Comparability

In this section we deal with those requesting rehearing of our conclusions regarding what ''comparable'' service is, who is eligible for that service, and how it is to be implemented. We reaffirm our finding that, as a matter of law, we have jurisdiction over the rates, terms and conditions of unbundled transmission service provided to retail customers. We also clarify that we have authority to order ''indirect'' unbundled retail transmission services and that if such transmission is ordered by us in the future, or if it is provided voluntarily, otherwise eligible customers may obtain such service under the open access tariff. We expect public utilities to provide such service in the future and, if they do not, we will not hesitate to order it.

We modify in two respects the definition of who is eligible for open access transmission service. First, we clarify that, with respect to service that this Commission is prohibited from ordering by section 212(h) of the Federal Power Act (retail wheeling directly to an ultimate consumer and ''sham'' wholesale wheeling), entities are eligible for such service under the tariff only if it is provided pursuant to a state requirement or is provided voluntarily. Second, we clarify that retail customers taking unbundled service pursuant to a state requirement (*i.e.*, direct retail service) are eligible for such service only from those transmission providers that the state orders to provide service. These changes are made to make clear that our rules cannot be used to circumvent the proscriptions placed on the Commission against ordering direct retail wheeling.

Ancillary Services

In this section we deal with petitions to rehear our definitions of ancillary services—those services such as scheduling, voltage control, and supplemental reserve service that must or can attend the providing of transmission service—as well as the provisions involving these services. We reaffirm that tariffs must separately state the charges for these services. We do modify some of the definitions of these services to conform to industry needs and practices. Most importantly, we make clear that the transmission provider's sale of ancillary services associated with providing basic transmission service is not a wholesale merchant function and thus does not violate the standards of conduct imposed with Order No. 889.

Coordination Arrangements

The requirement to provide non-discriminatory open access transmission applies to any agreement between utilities that contains transmission rates, terms or conditions. This includes pooling arrangements and agreements between companies contracting to provide each other mutually beneficial transmission services. In Order No. 888 we laid out rules under which the open access comparability requirements would apply to tight and loose power pools, public utility holding companies and bilateral coordination agreements.

We also set out principles that would govern our approval of independent system operator (ISO) agreements.

In this section we affirm the rules governing coordination agreements. In doing so we clarify the definition of ''loose pool.'' We also make clear that, unlike in other situations where we require utilities to provide not only the services they provide themselves but those they could provide themselves, we will require members of loose pools to offer to third parties only those transmission services that they provide themselves under their pool-wide agreements.

We also reaffirm our strong commitment to the concept of ISOs and the ISO principles described in Order No. 888. In doing so we reject arguments that we should require that ISOs be formed. At the same time, we emphasize that while there is no ''cookie-cutter'' approach to forming an acceptable ISO, the requirement of fair and non-discriminatory rules of governance (Principle One) and the requirement that ISO employees have no financial interest in the economic interests of power marketers—backed by strict conflict of interest provisions—(Principle Two) are fundamental to our approving any ISO.

Pro Forma Tariff Provisions

The pro forma tariff is the basic mechanism implementing the requirements of comparable open access transmission. It provides the details of the transmission service obligations imposed on jurisdictional utilities by the Rule. On rehearing we affirm most of the provisions set out in Order No. 888 for the pro forma tariff. We do make changes to conform the pro forma tariff to changes adopted under other sections (for example, the definition of ''eligible customer'').

The rehearing petitions raised many questions about how particular aspects of the tariff will work. For the most part, these questions cannot be answered generically, but must be resolved on a case-by-case basis in the context of specific fact situations. However, the petitions brought to light issues that require clarifications and in some cases revisions to the tariff. The most significant of these involve discounting practices, provisions governing priority of service and curtailment, and the reciprocity provision.

Discounting practices. Originally, we provided different rules depending upon whether the transmission provider was offering a discount to itself or an affiliate or offering a discount to a non-affiliate. In response to the rehearing petitions, we are making three significant changes to the discounting requirements to better permit the ready identification of discriminatory discounting practices while also providing greater discount flexibility.

First, any discount offered on transmission services (including supporting ancillary services) by a transmission provider or requested by any customer must now be made only over the OASIS. With this change, all will have the same, timely access to discounted services. In making this change, we clarify that a transmission provider may limit its discounted service to particular time periods.

Second, once the provider and customer agree on a discount, the details of the discounted service—the price, points of receipt and delivery, and length of service—must be immediately posted on the OASIS.

Third, we revise our Rule respecting what other transmission paths must be offered at a discount. Originally, in Order No. 888, we required that when a discount was offered over one path, the transmission provider would have to provide that discount over all other unconstrained paths on its system. We will no longer require this. Instead, the discount will be limited to those unconstrained paths that go to the same point(s) of delivery as the discounted service being provided on the transmission provider's system. The discount will extend for the same time period and must be offered to all transmission service customers.

Priority and Curtailment. We affirm the right of first refusal policy that reservation priority continues for firm service customers served under a contract of one year or more. We also affirm that curtailment must be made on a pro-rata basis and clarify that non-firm point-to-point service is subordinate to firm service. However, we clarify that the pro-rata curtailment requirement extends to only those transactions that alleviate the constraint.

Reciprocity. In Order No. 888 we conditioned the use of a public utility's open access service on the agreement that, in return, it is offered reciprocal service by non-public utilities that own or control transmission facilities. Such reciprocal service does not have to be through an open access tariff, i.e., a tariff available to all eligible customers, but may be limited to those public utilities from whom the non-public utility obtains open access service. We affirm the reciprocity condition. In doing so, however, we make several clarifications.

First, a public utility is free to offer transmission service to a non-public utility without requiring reciprocal service in return. In other words, it may voluntarily waive the reciprocity condition. However, if it chooses to do so, transmission service must be provided through the pro forma tariff. Alternatively, bilateral agreements for transmission service provided by the public utility will not be permitted.

Second, we clarify that under the reciprocity condition a non-public utility must agree to offer the Transmission Provider any transmission service the non-public utility provides or is capable of providing on its system. This means that the non-public utility undertaking reciprocity must have an OASIS and must operate under the standards of conduct imposed under Order No. 889 unless it is granted a waiver by the Commission or, where appropriate, by a regional transmission group (RTG) of which it is a member. We also clarify that a non-public utility cannot avoid its responsibilities by obtaining transmission service through other transmission customers. Further, the seller as well as the buyer in the chain of a transaction involving a non-public utility will have to comply with the reciprocity condition.

Third, we adhere to our decision not to treat generation and transmission (G&T) cooperatives and their member distribution cooperatives as a single unit. Thus, the reciprocity provision extends to the G&T Cooperative and not to its member distribution cooperatives.

Fourth, we clarify the ''safe harbor'' provision under which a non-public utility may get a Commission decision that its transmission tariff suffices to meet reciprocity. A non-public utility may limit the use of any reciprocity tariff that it voluntarily files at the Commission to those transmission providers from whom the non-public utility obtains open access service. A non-public utility also may satisfy reciprocity through bilateral agreements with a public utility. As a related matter, if a public utility believes a non-public utility is violating the reciprocity condition, it may file with the Commission a petition to terminate its service to the non-public utility.

Fifth, we clarify that non-public utilities may include stranded cost provisions in their reciprocity tariffs.

Sixth, the order on rehearing removes the term ''interstate'' from the reciprocity provisions. This is to make clear that reciprocity applies even to those who do not own or control interstate transmission facilities; *i.e.*, foreign utilities and those located in the ERCOT region of Texas.

As to local furnishing bonds held by some public utilities, we clarify that all costs associated with the loss of tax-exempt status of those bonds caused by providing open access transmission service are properly considered costs of providing that service. This includes costs of defeasing, redeeming, and refinancing those bonds.

Other Clarifications. In this order on rehearing we take the opportunity to clarify various other tariff provisions. Among these: Transmission providers do not have to take service under the open access tariff for transmitting power purchased on behalf of their bundled retail customers. Also, the ability to reserve capacity to meet the reliability needs of a transmission provider's native load applies equally to present transmission and transmission that is built in the future.

Implementation

On rehearing, we make no substantive changes to the implementation provisions originally required under Order No. 888. For the most part, the implementation process has been completed. Utilities have made the requisite tariff and compliance filings and public and non-public utilities have, through other orders, been provided guidance as to obtaining waivers of Order No. 888 and Order No. 889 requirements.

We emphasize that we do not require the abrogation of existing contracts. Rather, the Rule requires only that transmission providers offer transmission under the open access tariff in addition to existing service obligations. Commitments made under existing contracts will continue. Of course, both transmission providers and their customers may seek to revise the terms and conditions of existing contracts by making the necessary filings, as appropriate, under Sections 205 or 206 of the Federal Power Act.

State and Federal Jurisdiction

On rehearing we reaffirm our decision that when transmission service is provided to serve retail customers apart from any contract for the retail sale of power, i.e., when it is provided on an unbundled basis, that transmission service is under our jurisdiction. In today's market, and increasingly in the future as more states adopt retail wheeling programs, retail transactions are, and will be, broken down into products that are sold separately—transmission and generation—and sold by different entities. The exercise of our jurisdiction over the rates, terms and conditions of unbundled retail transmission will, therefore, become more important. We also recognize that states have jurisdiction over facilities used for local distribution.

On rehearing we also reaffirm the seven-factor test of Order No. 888 to distinguish transmission under our jurisdiction from state-jurisdictional local distribution. In doing so, we recognize that our test does not resolve all possible issues. There may be other factors that should be taken into account. The test, therefore, is designed for flexibility to include unique local characteristics and usages. To that end, we will continue to defer to state findings on these matters.

In addition, we clarify that states have the authority to determine the retail marketing areas of the electric utilities within their respective jurisdictions. We also recognize that states have the concomitant authority to determine the end user services these utilities provide.

Stranded Costs

On rehearing, we reaffirm our basic decisions surrounding the recovery of stranded costs. Utilities will be allowed the opportunity to seek to recover legitimate, prudent, and verifiable wholesale stranded costs. This opportunity is limited to costs associated with serving customers under wholesale requirements contracts executed on or before July 11, 1994 that do not contain explicit stranded cost provisions; and costs associated with serving retail-turned-wholesale customers.

We clarify that we will consider on a case-by-case basis whether to treat a contract extended or renegotiated without a stranded cost provision as an existing contract for stranded cost purposes.

In each case, the opportunity to seek stranded costs is limited to situations in which there is a direct nexus between the availability and use of a Commission-required transmission tariff and the stranding of the costs. The Rule does not allow the recovery of costs that do not arise from the new, accelerated availability of non-discriminatory transmission access.

The Commission also reaffirms its decision that stranded costs should be recovered from the customer that caused the costs to be incurred. The Commission is not requiring other remaining customers, or the utility, to shoulder a portion of its stranded costs that meet the requirements for recovery.

The Commission, as described in Order No. 888, will be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. With respect to such cases, we have made several changes.

First, the Commission has reconsidered its decision respecting cases involving existing municipal utilities that annex retail customer service territories. Under Order No. 888, we found that in such cases the Commission should not be the primary forum for determining stranded cost recovery. On rehearing we now find that such cases should fall within our province.

Second, we clarify that the opportunity for recovery of stranded costs associated with retail-turned-wholesale customers applies regardless of whether the customer or its new supplier is the one requesting and contracting for the transmission service. To this end, we have revised the definition of ''wholesale stranded cost.''

With respect to the recovery of stranded costs caused by unbundled retail wheeling, we affirm that the only circumstance in which we will entertain requests for these types of costs is when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required. We clarify that if a state regulatory authority has in fact addressed such costs, regardless of whether it has allowed full recovery, partial recovery or no recovery, utilities may not apply to the Commission to recover stranded costs caused by the retail wheeling.

Other

In this section we resolve questions concerning our information reporting requirements, regional transmission groups, and the special situations posed by utilities in the Pacific Northwest and by federal power marketing and similar agencies. Here we make some minor clarifications but make no significant changes to Order No. 888.

We are not persuaded that the information reporting requirements need to be changed at this time. Finally, we reject arguments that would have us fix generically any particular rate methodology for providing open access transmission service under the pro forma tariff.

II. Public Reporting Burden

This order on rehearing issues a number of minor revisions to the Final Rule. We find, after reviewing these revisions, that they do not, on balance, increase the public reporting burden.

The Final Rule contained an estimated annual public reporting burden based on the requirements of the Open Access Final Rule and the Stranded Cost Final Rule.[3] Using the

[3] 61 FR 21540 at 21543; FERC Stats. & Regs. ¶ 31,036 at 31,638 (1996). No comments were filed

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burden estimate contained in the Final Rule as a starting point, we evaluated the public burden estimate contained in the Final Rule in light of the revisions contained in this order and assessed whether this estimate needed revision. We have concluded, given the minor nature of the revisions, and their offsetting nature, that our estimate of the public reporting burden of this order on rehearing remains unchanged from our estimate of the public reporting burden contained in the Final Rule. The Commission has conducted an internal review of this conclusion and has assured itself that there is specific, objective support for this information burden estimate. Moreover, the Commission has reviewed the collection of information required by the Final Rule, as revised by this order on rehearing, and has determined that the collection of information is necessary and conforms to the Commission's plan, as described in the Final Rule, for the collection, efficient management, and use of the required information.

Persons wishing to comment on the collections of information required by the Final Rule, as modified by this order on rehearing, should direct their comments to the Desk Officer for FERC, Office of Management and Budget, Room 3019 NEOB, Washington, D.C. 20503, phone 202–395–3087, facsimile: 202–395–7285 or via the Internet at hillier__t@a1.eop.gov. Comments must be filed with the Office of Management and Budget within 30 days of publication of this document in the Federal Register. Three copies of any comments filed with the Office of Management and Budget also should be sent to the following address: Ms. Lois Cashell, Secretary, Federal Energy Regulatory Commission, Room 1A, 888 First Street, N.E., Washington, D.C. 20426. For further information, contact Michael Miller, 202–208–1415.

III. Background

In the Final Rule, we detailed the events that led up to this rulemaking, including the significant technical, statutory and regulatory changes that have occurred in the electric industry since the FPA was enacted in 1935.[4] In particular, we focused on the competitive influences of the Public Utility Regulatory Policies Act of 1978, the Congressional mandate in the Energy Policy Act of 1992 to encourage competition in electricity markets, and the need for reform in the industry if consumers are to achieve the benefits that greater competition can bring.

In the ten months since the Final Rule issued, competitive changes have escalated at an even faster pace in virtually all areas of the electric industry. These changes are driven not only by the Commission's Final Rule, but also by state restructuring initiatives and by continuing pressures from customers to take advantage of emerging competitive markets and the lower electricity rates they can bring.

All of the existing 166 public utilities that own, control or operate interstate transmission facilities (listed as Group 1 and Group 2 utilities in the Final Rule) have filed the Order No. 888 pro forma open access tariff or requested a waiver of the requirement. Similarly, they either have adopted an electronic information network or requested a waiver of the requirement. Five non-public utilities have submitted reciprocal transmission tariffs and more than 20 have requested a waiver of the reciprocity condition in the pro forma tariff.[5]

Significant competitive changes also have accelerated with respect to power pooling, state restructuring initiatives, and Independent System Operators (ISOs). Under Order No. 888 and subsequent implementation orders, the Commission required the filing of revised pooling agreements and joint pool-wide transmission tariffs by December 31, 1996, in order to remedy undue discrimination in transmission services provided through interstate power pooling arrangements. Among the power pool filings were a New England (NEPOOL) comprehensive restructuring proposal, a New York proposal, a Pennsylvania-New Jersey-Maryland (PJM) compliance filing and a Western Systems Power Pool filing.

In response to the Commission's encouragement in Order No. 888 of ISOs as a possible means for accomplishing comparable access, a number of utilities and states are well underway in developing this new institution. The fundamental purpose of an ISO is to operate the transmission systems of public utilities in a manner that is independent of any business interest in sales or purchases of electric power by those utilities. The Commission has received several proposals for forming ISOs, one as part of the multi-docketed filing engendered by California's restructuring plan, and others relating to power pool filings. A number of regions are also developing ISO proposals. Some regions previously considering regional transmission groups (RTGs), whose primary purpose is regional planning of transmission facility construction and upgrades, have now broadened their discussions to include an ISO.

Investor-owned utilities in California, at the order of both the state commission and the legislature, have filed proposals with the Commission that would transfer control of transmission facilities to an ISO in conjunction with the formation of a state-wide power exchange to facilitate both wholesale and retail access. While the case presents many complex issues for the Commission to resolve, the California proposal is fundamentally compatible with the pro-competitive open-access requirements of Order Nos. 888 and 889. The Commission's open-access policies therefore have provided a framework for California, and other states, to explore customer choice initiatives.

Other major regions of the country also are instituting ISOs. Member utilities of the PJM Power Pool filed competing ISO proposals with the Commission and are currently working to reconcile the differences between their proposals. The New York Power Pool recently filed a proposal to create an ISO and a power exchange for New York. The New England Power Pool is exploring a new industry structure for its region that centers on the creation of an ISO. Utilities and other market participants in the Electric Reliability Council of Texas have also formed an ISO. Discussions are underway among utilities from Virginia to Wisconsin in an attempt to create a Midwestern ISO. Members of the Mid-America Power Pool are discussing an ISO proposal. In the Pacific Northwest, utilities are involved in negotiations intended to lead to the formation of an independent grid operator (Indego).

The combined available generation resources of the utilities in these groups is on the order of 428 GW out of a total of approximately 732 GW for total U.S. resources (as of the end of 1996). Thus, assuming these ISO arrangements come to fruition, about three-fifths of the industry may have independent system operators controlling their transmission systems.

Moreover, every state but one has proposed or is considering or developing retail competition programs. For example, New Hampshire, Illinois

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.

and Massachusetts began pilot programs in the past year, and retail transmission service for these pilot programs currently is being taken pursuant to tariffs approved by both the state commissions and this Commission. The Massachusetts Department of Public Utilities has sent a proposal to the state legislature calling for retail competition to begin in January 1998. The New York Public Service Commission has issued an order proposing that retail competition begin in early 1998. The New Jersey Board of Public Utilities has issued a proposal permitting customer choice beginning in October of 1998. The Vermont Public Service Board has sent a plan to the legislature recommending that full customer choice begin by the end of 1998. The Arizona Corporation Commission has adopted rules to phase in competition over four years, beginning in January 1999. Recently, the Maine Public Utilities Commission issued a final report and recommendation to the legislature for retail competition to begin in January 2000. In addition, Rhode Island and Pennsylvania both have new laws requiring customer choice. These are only a few of the many state initiatives that are under way that will dramatically alter the structure of the electric industry.

Since Order No. 888 was issued, significant efforts also have been made to ensure that reliability of the transmission grid is maintained and that reliability criteria are compatible with competitive markets. The North American Electric Reliability Council (NERC) has continued its efforts to broaden its membership and to fashion reliability requirements to fit a more competitive electric power industry. For example, the NERC Board of Directors voted to require mandatory compliance by all power market participants with its reliability standards. NERC is also establishing new entities called regional security coordinators to oversee the stability of grid operations and to direct the development of an extensive new communications network. Various NERC committees are considering ways to improve the tracking of power transactions, identify the network impacts of transactions, and reflect the actual flow of power over the network when making reservations for transmission service. These efforts are likely to intensify as the industry continues to adapt to competitive changes occurring in the marketplace.

Thus, all segments of the electric industry have taken significant steps in the past year in response to the emerging wholesale competitive markets enabled by Order No. 888 as well as state retail competition initiatives. The competitive framework established by Order No. 888, whose centerpiece is non-discriminatory transmission services and a fair and orderly stranded cost recovery mechanism, is critical to the successful transition to, and full development of, the industry restructuring proposals that are well underway in all major regions of the country.

IV. Discussion

A. Scope of the Rule

1. Introduction

Rehearing Requests

Severability of Rules

Several entities assert that the Commission should find that the requirements of open access transmission and stranded cost recovery are not severable.[6] They argue that if one of these provisions is invalidated by a court or otherwise removed, the orders in their entirety should be withdrawn or stayed pending reconsideration by the Commission, and public utilities should be allowed to withdraw or file amended transmission tariffs.

Commission Conclusion

The Commission will not, at this time, make any determination whether or not the open access transmission, stranded cost recovery and OASIS provisions of Order Nos. 888 and 889 are severable. Accordingly, we make no finding whether, if one of these provisions is invalidated, Order Nos. 888 and 889 should be withdrawn or stayed in their entirety. We believe that our decisions in Order Nos. 888 and 889 will be upheld by the courts. Moreover, it would be premature to consider the appropriateness of a stay or withdrawal at this time. Circumstances at the time of any court order would dictate how we should proceed and we would consider all such circumstances, and the entirety of our policy decisions, before determining how to respond to a court decision.

2. Functional Unbundling

In the Final Rule, the Commission found that functional unbundling of wholesale generation and transmission services is necessary to implement non-discriminatory open access transmission.[7] At the same time, the Commission recognized that additional safeguards were necessary to protect against market power abuses. Thus, the Commission adopted a code of conduct, discussed in detail in the final rule on OASIS, to ensure that the transmission owner's wholesale power marketing personnel and the transmission customer's power marketing personnel have comparable access to information about the transmission system. The Commission also noted that section 206 of the FPA is available if a public utility seeks to circumvent the functional unbundling requirements.

As a further precaution against unduly discriminatory behavior, the Commission stated that it will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. The Commission also indicated that it would continue to observe both the evolution of competitive power markets and the progress of the industry in adapting structurally to competitive markets. If it subsequently becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, the Commission indicated that it would reevaluate its position and decide whether other mechanisms, such as ISOs, should be required.

The Commission concluded that functional unbundling, coupled with these safeguards, is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. In the absence of evidence that functional unbundling will not work, the Commission indicated that it was not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time.

Rehearing Requests

Several entities disagree with the Commission's decision to require functional unbundling of wholesale generation and transmission as a means of assuring non-discriminatory open access transmission.[8] American Forest & Paper argues that utilities must be required to divest or spin-off their generating assets through operational unbundling or divestiture. It alleges that it was arbitrary and capricious, and not supported by evidence, for the Commission to rely on a monopolist's code of conduct to protect against monopoly abuses. Nucor asserts that a financial conflict of interest remains and that the Commission cannot monitor the exchanges of information between utility generation and transmission employees. It declares that a credible

[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.

information disclosure requirement is needed that makes generation cost and production data visible to all participants on a same-time basis. NY Municipal Utilities also believes that the Commission did not go far enough and argues that the Commission should have required operational unbundling, at least for tight power pools.

Commission Conclusion

The Commission reaffirms its finding in the Final Rule that, based on the information available at this time, functional unbundling, along with the flexible safeguards discussed in the Final Rule, is a reasonable and workable means of assuring non-discriminatory open access transmission. We see no need to adopt a more intrusive and potentially more costly approach at this time based on speculative allegations that functional unbundling may not work and that more severe measures may be needed. Indeed, despite a number of opportunities to do so, no entity has submitted any evidence suggesting that this less intrusive approach would not work. We do emphasize, however, that we have not adopted a rigid approach, but have indicated a willingness to monitor the situation and, if events require, reevaluate our decision and decide whether another mechanism may be more appropriate. Until we see evidence that functional unbundling will not work, we will continue to require functional unbundling, with the safeguards enumerated in the Final Rule and in Order No. 889.

3. Market-Based Rates

a. Market-Based Rates for New Generation

In the Final Rule, the Commission codified its determination in *Kansas City Power & Light Company* (*KCP&L*) [9] that the generation dominance standard for market-based sales from new capacity should be dropped.[10] The Commission explained that it had yet to find an instance of generation dominance in long-run bulk power markets and no commenter had presented any evidence to that effect. However, the Commission emphasized that it will not ignore specific evidence presented by an intervenor that a seller requesting market-based rates for sales from new generation nevertheless possesses generation dominance.

The Commission further clarified that dropping the generation dominance standard for new capacity does not affect the demonstration that an applicant must make in order to qualify for market-based rates for sales from its existing generating capacity.

Rehearing Requests

Several entities take issue with the Commission's determination to drop the generation dominance standard for market-based sales from new capacity.[11] American Forest & Paper argues that the Commission should delay its decision until effective competition has been demonstrated to exist in all markets. SC Public Service Authority maintains that the Commission must determine on a case-by-case basis whether public utilities have market power (for both existing and new capacity). It further argues that the Commission must develop an analysis of structural conditions to use in assessing the potential for market power consistent with that used by DOJ and FTC in merger proceedings and that reflects the conditions of the industry. SC Public Service Authority also asserts that the Commission must require as a condition of market rates for sales in the bulk power market, which it defines to be limited to sales to integrated utilities, that the selling utility file rate cases with the Commission and the applicable state commissions to avoid subsidization by captive consumers.

TDU Systems alleges that the long-run bulk power market upon which the *KCP&L* decision was based is overly broad and ignores the distinction between firm power, which ''entities subject to others' market power are most commonly in need of'' and other bulk power services. TDU Systems take issue with the Commission's conclusion in *KCP&L* that large numbers of capacity offers from IPPs and QFs demonstrate that the market abounds with competitors. TDU Systems argues that the Commission's ''assumption that large numbers of offers of *power* equate with large numbers of offers of *firm* power is questionable at best, and very likely incorrect.'' [12] Similarly, LEPA argues that the Commission ignored evidence submitted by LEPA in comments ''that the transmission dominant utility still retained monopoly power over RQ [requirements] markets on which LEPA's members are dependent for their bulk power supply.'' Because the Commission ignored the RQ market and the evidence of concentration in that market, LEPA asserts that the Commission's decision is reversible error. LEPA further argues that the Commission ignored the undisputed testimony of LEPA's witness that reliability requirements constrain the geographic scope of the RQ market severely.

San Francisco argues that the burden to demonstrate affirmatively the absence of capacity constraints as a precondition to receiving authority to charge market-based rates for sales from new capacity should be upon public utility applicants, who possess the information concerning capacity constraints.

Commission Conclusion

We reaffirm our decision to codify the determination in *KCP&L* that the generation dominance standard for market-based sales from new capacity should be dropped. Petitioners have not presented any evidence that demonstrates generation dominance in long-run bulk power markets and, as discussed in Order No. 888, we have found no such evidence of generation dominance in any of the numerous market-based rate cases decided by the Commission since *KCP&L*. In addition, as described in Order No. 888, the Commission will consider evidence of generation dominance, including generation dominance that results from transmission constraints, when such evidence is presented by an intervenor in a market-based rate case in which a utility seeks market-based pricing associated with new capacity.

American Forest & Paper's argument that the Commission should delay codification of *KCP&L* until effective competition has been demonstrated to exist in all markets ignores the fact that we have eliminated the generation dominance standard for market-based rates from new capacity only, and that the generation standard still applies to applications for market-based rates from existing generation. Other entities similarly argue that other markets in which utilities may sell power from new capacity may be highly concentrated with respect to generation, or that these utilities may otherwise be able to exert market power. Specifically, TDU Systems and LEPA express concern that the new policy may result in the exercise of market power over very specific bulk power products.

To allay these concerns, we note that eliminating the generation dominance showing applies only to sales from new capacity. It does not apply to entire classes of service or to specific products. In addition, the policy eliminates the showing only as a matter of routine in each filing. We reemphasize that the Commission will consider specific evidence of generation dominance

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

[10] 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.

associated with new capacity at the time the seller seeks market-based rates for the new capacity, including whether the addition of the new capacity, when combined with existing capacity, results in generation dominance. This clearly includes situations where existing sources of generation must be combined with new resources to produce a firm power supply. Where entry barriers are a concern, intervenors are free to raise the issue.

SC Public Service Authority also raises a number of concerns relating to the ability of utilities to exercise market power if they are permitted to sell new capacity at market-based rates. These concerns generally include how the Commission determines product and geographic markets, and the standards used to determine whether sellers can exercise market power. In response to these concerns, as noted above public utility owners of new capacity must still seek case-by-case approval before they can sell power from new capacity at market-based rates and, as stated in the Final Rule, intervenors may present specific evidence that a seller requesting such market rates possesses generation dominance or otherwise has market power.[13] These requirements include considerations of transmission market power, whether other barriers to entry exist and whether there is evidence of affiliate abuse or reciprocal dealing.

b. Market-based Rates for Existing Generation

In the Final Rule, the Commission found that there is not enough evidence on the record to make a generic determination about whether market power may exist for sales from existing generation.[14] The Commission indicated that it would continue its case-by-case approach that allows market-based rates based on an analysis of generation market power in first tier and second tier markets.[15] The Commission further indicated that while it will continue to apply the first-tier/second-tier analysis, it will allow applicants and intervenors to challenge the presumption implicit in the Commission's practice that the relevant geographic market is bounded by the second-tier utilities. Finally, the Commission stated that it would maintain its current practice of allowing market-based rates for existing generation to go into effect not subject to refund.[16] To the extent that either the applicant or an intervenor in individual cases offers specific evidence that the relevant geographic market ought to be defined differently than under the existing test, the Commission indicated that it will examine such arguments through formal or paper hearings.

Rehearing Requests

No rehearing requests were filed with respect to this matter.

4. Merger Policy

In the Final Rule, the Commission explained that it had issued a Notice of Inquiry (NOI) on the Commission's merger policy in Docket No. RM96–6–000.[17] The Commission indicated that it will review whether its criteria and policies for evaluating mergers need to be modified in light of the changing circumstances, including the Final Rule, that are occurring in the electric industry. The Commission concluded that it would review its merger policy in the ongoing NOI proceeding.[18]

Rehearing Requests

No rehearing requests were filed with respect to this matter.

Commission Conclusion

We note that on December 18, 1996, the Commission issued, in the NOI proceeding, a Policy Statement that updates and clarifies the Commission's procedures, criteria and policies concerning public utility mergers.[19]

5. Contract Reform

Requirements and Transmission Contracts

In the Final Rule, the Commission concluded that it was not appropriate to order generic abrogation of existing requirements and transmission contracts, but concluded nonetheless that the modification of certain requirements contracts (those executed on or before July 11, 1994) on a case-by-case basis may be appropriate.[20] The Commission further concluded that, even if customers under such requirements contracts are bound by so-called *Mobile-Sierra* clauses, they ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

The Commission found that it would be against the public interest to permit a *Mobile-Sierra* clause in an existing wholesale requirements contract[21] to preclude the parties to such a contract from the opportunity to realize the benefits of the competitive wholesale power markets. Thus, it explained, a party to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract. The party, however, still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified.

The Commission explained that this finding complements the Commission's 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 the Final Rule. Accordingly, the Commission required that any contract modification approved under this Section must provide for the utility's recovery of any costs stranded consistent with the contract modification. Further, the Commission concluded that if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.

Coordination Agreements

The Commission concluded that to assure that non-discriminatory open access becomes a reality in the relatively near future, it was necessary to modify existing economy energy coordination agreements. The Commission stated that it would condition future sales and

[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.

[15] *See, e.g.*, Southwestern Public Service Company, 72 FERC ¶ 61,208 at 61,996 (1995), *reh'g pending.*

[16] The Final Rule contained a typographical error in which the word ''not'' was erroneously omitted.

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

[18] 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.

purchase transactions under existing economy energy coordination agreements [22] to require that the transmission service associated with those transactions be provided pursuant to the Final Rule's requirements of non-discriminatory open access, no later than December 31, 1996. The Commission also required that, for new economy energy coordination agreements [23] where the transmission owner uses its transmission system to make economy energy sales or purchases, the transmission owner must take such service under its own transmission tariff as of the date trading begins under the agreement.[24]

Finally, the Commission concluded that it would not require the modification of non-economy energy coordination agreements. However, the Commission noted that this does not insulate such agreements from complaints that transmission service provided under such agreements should be provided pursuant to the Final Rule pro forma tariff.

Rehearing Requests

Various utilities oppose the Commission's finding that it is in the public interest to permit the modification of existing requirements contracts that contain *Mobile-Sierra* clauses. On the other hand, a number of customers assert that the Commission did not go far enough and seek enhanced contract reformation rights.

Utilities Against Contract Reformation

Several utilities argue that the Commission's finding is not supported by substantial evidence.[25] Utilities For Improved Transition asserts that the Commission cannot rely on economic theory as a substitute for substantial evidence.[26] It argues that the record in this proceeding demonstrates that the marketplace is becoming increasingly competitive without mandatory tariffs, which is evidence of market health, not market problems. It further argues that even if undue discrimination is proven, the remedy is not needed because the record shows that existing programs are meeting the industry's needs.

Southwestern argues that the Commission has improperly chosen to ignore the public interest standard and has failed to make the contract specific analysis here that it performed in *Northeast Utils. Serv. Co.*, 66 FERC ¶ 61,332 (1994), *aff'd*, 55 F.3d 686 (1st Cir. 1995). PSE&G and Carolina P&L also argue that the Commission failed to demonstrate the ''unequivocal public necessity'' for generically abrogating the *Mobile-Sierra* clauses and assert that the Commission has presented no evidence as to how the public interest will be served by abrogating these contracts. PSE&G and Carolina P&L further argue that the Commission cannot avoid making a public interest determination ''by the simple expedient of asserting that the public interest requires it to ignore the *Mobile-Sierra* clauses that required that public-interest determination in the first place.'' [27]

Union Electric and PSE&G argue that the Commission, in justifying its public interest finding, inappropriately focused on the interests of the parties to the contract instead of on whether non-parties will be adversely affected by the existing contracts.

Public Service Co of CO asserts that the Commission should clarify the definition of requirements contract to include long-term block purchases of electricity. It states that it purchases a large percentage of its system requirements under long-term block purchase agreements, and that under the Commission's abrogation policy in Order No. 888, its ability to abrogate these supply arrangements would be treated differently because its contracts do not meet the definition of a ''wholesale requirements contract,'' as defined in new section 35.26(b)(1) of the Commission's Regulations. Public Service Co of CO further asserts that the Commission has not adequately explained why it is appropriate or in the public interest to allow partial requirements customers to abrogate their contracts, but not similarly to allow a public utility to abrogate its supply arrangements.[28]

PSE&G and Carolina argue that the availability of stranded cost recovery cannot support allowing customers to modify rates under *Mobile-Sierra* clauses that required that public-interest determination in the first place.

PSE&G and Carolina P&L also argue that no *Mobile-Sierra* contracts entered into after October 24, 1992 (the date EPAct became law) should be subject to the Rule because since that date customers have been able to apply for an order under section 211 to have power transmitted to them from suppliers other than the utility to whom they are interconnected.

PSE&G requests that the Commission clarify that the just and reasonable standard used in considering a contract abrogation claim will be limited to a determination of whether the rate is just and reasonable within the cost-based zone of reasonableness of the selling public utility. Such an analysis, PSE&G asserts, should not include a comparison to what other utilities offer to their customers.[29]

Customers Seek Enhanced Contract Reformation Rights

TAPS argues that the Commission should apply a just and reasonable standard to requests by all ''victims'' of undue discrimination to seek modifications of requirements or transmission contracts, whether they are subject to *Mobile-Sierra* or not. On the other hand, TAPS asserts that utilities should be bound to the bargain they extracted from transmission customers. Wisconsin Municipals request that the Commission clarify that parties may seek mandatory abrogation of preexisting transmission contracts or provisions and that the Commission will apply a rebuttable presumption that terms and conditions inferior to the pro forma tariff are unjust and unreasonable on their face.

CCEM argues that requirements customers should receive blanket conversion rights. At a minimum, CCEM asserts, if a customer seeks conversion, the burden of proof in the proceeding should shift to the utility. CCEM also emphasizes that the question remains why conversion was deemed essential in natural gas markets, but not in the transition to competition in the electric industry.

Blue Ridge argues:

> In neither the power supply nor transmission access case should a provider be allowed to modify existing power supply contracts under any but the *Mobile Sierra* public interest burden of proof. In both the power supply or transmission access cases, the Commission should articulate the suggested standards for what constitutes a *prima facia* case. [[30]]

Commission Conclusion

Before responding to the rehearing arguments raised, we wish to clarify our *Mobile-Sierra* findings. We explained in Order No. 888 that we were making two

[22] The Commission defined ''existing'' as those agreements executed prior to 60 days after publication of the Final Rule in the FEDERAL REGISTER.

[23] The Commission defined ''new'' as those agreements executed 60 days after publication of the Final Rule in the FEDERAL REGISTER.

[24] 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.

[26] 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.

complementary public interest findings. First, as discussed further in Section IV.J, we found that it is in the public interest to permit public utilities to seek stranded cost amendments to existing requirements contracts with *Mobile-Sierra* clauses. Second, we found that a ''party'' to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract, but still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified. We clarify that, in making this second finding, our reference to a ''party'' to a requirements contract containing a *Mobile-Sierra* clause was directed at modification of contract provisions by *customers.* [31] Additionally, it applies to any contract revisions sought, whether or not they relate to stranded costs. [32]

In response to the *Mobile-Sierra* rehearing arguments described above, as well as the *Mobile-Sierra* arguments described in Section IV.J concerning our determinations regarding stranded cost amendments to contracts, the Commission believes it is important to first address the general context in which our *Mobile-Sierra* determinations have been made. In Order No. 888, the Commission removed the single largest barrier to the development of competitive wholesale power markets by requiring non-discriminatory open access transmission as a remedy for undue discrimination. This action carries with it the regulatory public interest responsibility to address the difficult transition issues that arise in moving from a monopoly, cost-based electric utility industry to an industry that is driven by competition among wholesale power suppliers and increasing reliance on market-based generation rates.

There are two predominant, overlapping transition issues that arise as a result of our actions in this rulemaking: first, how to deal with the uneconomic sunk costs incurred, and second, how to deal with the contracts that were entered into, under an industry regime that rested on a regulatory framework and set of expectations that are being fundamentally altered. To address these issues, the Commission has balanced a number of important interests in order to achieve what it believes will be a fair and orderly transition to competitive markets. These interests include the financial stability of the electric utility industry and permitting customers to obtain the benefits of competitive markets without undue disruption or unfairness to other customers or industry participants.

As the above rehearing arguments demonstrate, there is no consensus on how the Commission should manage the transition. In fact, parties offer diverse and conflicting views as to what the Commission should do regarding existing contracts. Some would have us let all contracts run their course with no opportunity for customers to modify or terminate their contracts, no matter how long the contracts or how onerous their terms. Others advocate automatic generic abrogation of all contracts. Yet others want a guaranteed automatic right to renew a contract if it happens to contain favorable rates and terms.[33]

Rather than adopting one extreme position or the other, the Commission has taken a measured approach with regard to contract modification, including modification of contracts that contain *Mobile-Sierra* clauses. Our goal is to balance the desire to honor existing contractual arrangements with the need to provide some means to accelerate the opportunity of parties to participate in competitive markets. To accomplish this balance, the Commission, first, has made *Mobile-Sierra* public interest findings (discussed further below) only as to a limited set of contracts: those wholesale requirements contracts executed on or before July 11, 1994, which is the date of our first stranded cost proposed rulemaking and which served to put the industry and customers on notice that future contracts should explicitly address the rights, obligations and expectations of parties, including stranded cost obligations.[34]

Second, with regard to contract modifications sought by utilities, as discussed in more detail in Section IV.J, utilities that seek to add stranded cost provisions have a high evidentiary burden to meet before they can add contract provisions that permit stranded cost recovery beyond the end of their contract terms; the burden is particularly high in the case of contracts with notice provisions. With regard to modifications of contract provisions that do not relate to stranded costs, a utility with a *Mobile-Sierra* contract clause will have the burden of showing that the provisions are contrary to the public interest.[35]

Third, with regard to contract modifications sought by customers, a customer will have to show that the provisions it seeks to modify are no longer just and reasonable.[36] If a customer seeks to shorten or eliminate the term of an existing contract, any contract modification approved by the Commission will take into account the issue of appropriate stranded cost recovery by the customer's supplying utility.

In permitting customers the *opportunity* to seek these types of modifications, even for contracts that contain *Mobile-Sierra* clauses, the Commission has based its public interest findings on the unprecedented industry changes facing utilities and their customers. While, as we stated in the Final Rule, there is no market failure in the electric industry that would justify generic abrogation of existing contracts, nevertheless the industry is in the midst of fundamental change. We cannot conclude that it is in the public interest to require all customers to be

[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).

[32] 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.

held to requirements contracts that were executed under the prior industry regime, no matter what the circumstances of those contracts.

In response to parties who challenge the Commission's finding that it would be against the public interest to deny customers an opportunity to seek modification of wholesale requirements contracts executed on or before July 11, 1994,[37] these parties ignore the fact that these contracts were entered into during an era in which transmission providers exercised monopoly control over access to their transmission facilities.[38] The majority of customers under these types of contracts were captive, *i.e.*, they had no realistic choice but to purchase generation from their local utility because they had no transmission to reach another supplier. Many of these contracts were the result of uneven bargaining power between customers and monopolist transmission providers.[39] While monopolist transmission providers may not have exercised monopoly power in all situations,[40] the unprecedented competitive changes that have occurred (and are continuing to occur) in the industry may render their contracts to be no longer in the public interest or just and reasonable. These changed circumstances, discussed at length in the Final Rule, and the further changes that will occur as a result of open access transmission, may affect whether such contracts continue to be just and reasonable or not unduly discriminatory both as to the direct customers of the contracts, as well as to indirect, third-party consumers as well.[41]

We therefore reject arguments that there is no ''evidence'' to support our finding that it is in the public interest to permit review of these contracts in light of the specific circumstances surrounding the contracts and in light of dramatically changed industry circumstances. We emphasize, however, that our decision is to permit an *opportunity* for review and that we will require a case-by-case showing that any modifications should be permitted. [42] As we explained in the Final Rule, this decision complements our decision that it is in the public interest to permit amendments to add stranded cost provisions to existing contracts if case-by-case evidentiary burdens are met.

As we discuss further in our detailed stranded cost discussion in Section IV.J, we do not interpret the *Mobile-Sierra* public interest standard as practically insurmountable [43] in the extraordinary situation before us where historic statutory and regulatory changes have converged to fundamentally change the obligations of utilities and the markets in which both they and their customers will operate. The ability to meet our overarching public interest responsibilities and to protect consumers would be virtually precluded if we were to apply a practically insurmountable standard of review before taking into account these fundamental industry-wide changes.[44]

With respect to Public Service Co of CO's argument, we disagree that the definition of a wholesale requirements contract should be modified to include a long-term block purchase of electricity. In the majority of circumstances, such long-term supply contracts are voluntary arrangements in which neither party had market power. It would be inappropriate to make generic *Mobile-Sierra* findings as to these types of contracts. Parties can avail themselves of the section 205 and 206 procedures already available to them if they want to seek modification of such contracts.

Finally, we reject CCEM's argument that all customers should receive automatic conversion rights because customers were provided such a right in the restructuring of the natural gas industry. We have taken, as is within our discretion, a substantially different approach here from that taken when we restructured the natural gas industry. As we stated in the Final Rule, and as alluded to above, at the time the Commission addressed this situation in the natural gas industry it was faced with shrinking natural gas markets, statutory escalations in natural gas ceiling prices under the Natural Gas Policy Act, and increased production of gas.[45] Moreover, the natural gas industry was plagued with escalating take-or-pay liabilities.

There was a market failure in the natural gas industry that required the

[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.

[38] 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.

[39] 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.

[40] 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.

[41] 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.

[44] 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.

extraordinary measure of generically allowing all customers to break their contracts with pipelines. In contrast, market circumstances in the electric industry today do not compel generic abrogation of contracts. The more moderate approach we have taken will permit us to take into account the fundamental industry changes that have occurred (and will continue to occur), to balance the interests of all affected parties, and to help avoid drastic shocks to industry participants.

Right of First Refusal

In the Final Rule, the Commission concluded that all firm transmission customers (requirements and transmission-only), upon the expiration of their contracts or at the time their contracts become subject to renewal or rollover, should have the right to continue to take transmission service from their existing transmission provider.[46] If not enough capacity is available to meet all requests for service, the right of first refusal gives the existing customer who had contractually been using the capacity on a long-term, firm basis the option of keeping the capacity. However, the limitations imposed by the Commission are that the underlying contract must have been for a term of one-year or more and the existing customer must agree to match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time, and to accept a contract term at least as long as that offered by the potential customer.[47] Moreover, the Commission indicated that this right of first refusal is an ongoing right that may be exercised at the end of all firm contract terms (including all future unbundled transmission contracts).

Requests for Rehearing

On rehearing, most petitioners agree with or do not contest the notion of providing existing transmission customers with a right of first refusal, but many have requested modification or clarification of the Commission-imposed limitations on such a right. A variety of transmission customers assert that the Commission's right of first refusal provision fails to adequately protect existing transmission customers' rights to continued service and seek changes to the Commission's provision. On the other hand, a number of utilities believe that the Commission should provide additional restrictions on the right of first refusal.

Customers' Positions

APPA argues that (1) existing customers should only have to agree to service that matches the term of any power supply contract for which it will use the transmission arrangement or, in the absence of a generation contract, one year, and (2) the pricing provision should be changed to reflect the current just and reasonable rate, as approved by the Commission, for similar transmission service.

NRECA also argues that the term and pricing provisions of section 2.2 need to be changed. With respect to the term of the contract the customer should be required to match, NRECA asserts that it should be one year, which corresponds to the definition of long-term firm service in the tariff. With respect to the rate, NRECA requests that the Commission cap the obligation to match the price offered by another customer at the maximum transmission rate the incumbent customer is obligated to pay to the transmission provider at the close of the prior contract term.

TDU Systems argue that the right of first refusal provision fails to take into consideration amounts that TDUs have contributed to the development of the transmission systems through prior transmission rates. TDU Systems are concerned about the possibility of an increase in the price of transmission capped only by the cost of increasing the capacity of the provider's transmission system.

TAPS requests that the Commission clarify that the transmission provider may only charge its then effective rates for existing, non-constrained transmission capacity because to allow opportunity or expansion costs would perpetually put the existing transmission customers on the margin at the end of their contract terms subjecting them to higher rates than the transmission provider.[48]

Blue Ridge raises a possible discrepancy between the language in the tariff and the language in the preamble. It asserts that section 2.2 ''requires the existing customer to 'pay the current just and reasonable rate, as approved by the Commission,' while the Regulatory Preamble requires the customer to 'match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time.' Order No. 888, *mimeo* at 88.''

Tallahassee asks the Commission to clarify that the right of first refusal to presently bundled transmission capacity accrues to the power customer paying the bundled rate and not to the intermediary acting on behalf of the customer.

AEC & SMEPA maintain that the price and term limitations of section 2.2 would place TDUs at a competitive disadvantage vis-a-vis the transmission provider by subjecting TDUs to incremental costs, including the costs of system upgrades, if other new customers are vying to use the transmission system. They state that the Commission must provide existing transmission customers the same rights as the transmission provider's other native load customers.

Utilities' Positions

PSNM argues that imposing a right of first refusal is inconsistent with the Commission's finding that contracts should not be abrogated. In effect, it argues that imposition of the right of first refusal abrogates existing contracts executed with the expectation that capacity could be recalled for the utility's own use upon expiration of the contracts. PSNM explains that it has a constrained transmission system and has been balancing specific contract durations against projected future native loads so that required capacity may be made available for use by third parties in the short-term, but not be committed to those parties at the time it is needed to be recalled. Moreover, PSNM asserts that Order No. 888 is not supported by the right of first refusal process of Order No. 636 because the Commission does not have abandonment authority under the FPA and its authority to require continuation of service is not well-defined and is controversial.[49]

Utilities For Improved Transition and Florida Power Corp argue that section 2.2 of the pro forma tariff should be modified by ''restricting rollover rights to the same points of receipt and delivery as the terminating service and

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

[47] 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.).

by providing the customer notice of a competing application and 90 days in which to file its own application for service for a term at least as long as the competing application.'' (Florida Power Corp at 11–13; Utilities For Improved Transition at 50–53). Similarly, EEI argues that to obtain a priority for continuation of service, customers must be seeking service that is substantially similar to or a continuation of the service they already receive and must be subject to a time limit on the reservation priority. CSW Operating Companies assert that it is unclear how the right of first refusal provision will be implemented.

State Commission Position

VT DPS states that the right of first refusal provision offers inadequate protection: ''While it is true that the existing customer could secure a five year transmission arrangement under a *new* contract, its right to *continuous* service is placed in jeopardy if it does not match the six year offer of the competing bidder.'' VT DPS argues that the Commission's bare bones provision opens the opportunity for competitive mischief by the transmission provider. VT DPS proposes that ''the existing customer should be able to renew its contract by matching the highest transmission price offered in the marketplace (up to the tariff maximum rate) and by offering to extend its contract for seven years or the prevailing length of firm transmission contracts in the marketplace, whichever is shorter.'' (VT DPS at 17–21).

Commission Conclusion

In this order, the Commission reaffirms its decision to give a reservation priority to existing and future firm transmission customers served under a contract of one year or more, and also addresses petitioner arguments regarding the Commission-imposed limitations associated with the exercise of that priority.

Rationale

Our policy rationale for giving an existing firm transmission customer (requirements and transmission-only),[50] served under a contract of one year or more, a reservation priority (right of first refusal) when its contract expires is that it provides a mechanism for allocating transmission capacity when there is insufficient capacity to accommodate all requestors. If there are capacity limitations and both customers (existing and potential) are willing to pay for firm transmission service of the same duration, the right of first refusal provides a tie-breaking mechanism that gives priority to existing customers so that they may continue to receive transmission service.[51]

Contract Term Limitation

We reject arguments to modify the requirement in section 2.2 that existing long-term firm transmission customers seeking to exercise their right of first refusal must agree to a contract term at least as long as that sought by a potential customer. The objective of a right of first refusal is to allow an existing firm transmission customer to continue to receive transmission service under terms that are just, reasonable, not unduly discriminatory, or preferential. Absent the requirement that the customer match the contract term of a competing request, utilities could be forced to enter into shorter-term arrangements that could be detrimental from both an operational standpoint (system planning) and a financial standpoint.

Rate Limitation

We also reject the proposition that either existing wholesale customers or transmission providers providing service to retail native load customers should be insulated from the possibility of having to pay an increased rate for transmission in the future. The fact that existing customers historically have been served under a particular rate design does not serve to ''grandfather'' that rate methodology in perpetuity. Because the purpose of the right of first refusal provision is to be a tie-breaker, the competing requests should be substantially the same in all respects.[52]

In response to Blue Ridge's concern regarding a discrepancy between the language in section 2.2 of the tariff and the preamble, we clarify that existing customers who exercise their right of first refusal will be required to pay the just and reasonable rate, as approved by the Commission at the time that their contract ends.[53]

Mechanics of the Right of First Refusal Process

CSW Operating Companies asked the Commission to clarify the mechanics of exercising the right of first refusal. We have determined not to specify in this order the mechanics by which the right of first refusal mechanism will be exercised for existing firm transmission arrangements. Instead, we intend to address such issues on a case-by-case basis, if and when a dispute arises. However, we encourage utilities and their customers to include specific procedures for exercising the right of first refusal in future transmission service agreements executed under the pro forma tariff. And of course, utilities are free to make section 205 filings to propose additions to the pro forma tariff to generically specify procedures for dealing with the issues.

Existing Contracts

By providing existing customers a right of first refusal, we are not, as PSNM claims, abrogating contracts. Moreover, PSNM's concern that the right of first refusal will prohibit utilities from ''recalling'' existing capacity to meet native load growth that was anticipated at the time existing third-party transmission contracts were executed can be addressed in the context of a specific filing by a utility demonstrating that it had no reasonable expectation of continuing to provide transmission service to the wholesale transmission customer at the end of its contract. For future transmission contracts, Order No. 888 permits utilities to reserve existing transmission capacity to serve the needs (current and reasonably forecasted) of its existing native load (retail) customers. Moreover, if a utility provides firm transmission service to a third party for a time until native load needs the capacity, it should specify in the contract that the right of first refusal does not apply to that firm service due to a reasonably forecasted need at the time the contract is executed.

Informational Filings

With respect to all existing requirements contracts and tariffs that provide for bundled rates, the Commission, in the Final Rule, required all public utilities to make informational

[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.

[51] 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.

filings setting forth the unbundled power and transmission rates reflected in those contracts and tariffs.[54]

Requests for Rehearing

Utilities For Improved Transition and VEPCO ask the Commission to clarify whether the unbundled transmission rate should be the current transmission tariff rate (bundled rate likely not to include the current price for transmission service) or an approximation of the rate at the time the contract was executed (may be impossible to determine).

Commission Conclusion

We previously addressed the determination of the unbundled transmission rate in informational filings in an order issued October 16, 1996.[55] In that order, we noted that Order No. 888 does not prescribe any specific method for calculating separately-stated transmission and generation rates and public utilities have used different methods in their informational filings. Because of the general lack of controversy over the informational filings and the fact that they are for informational purposes as a benefit to existing customers, the Commission accepted the vast majority of the informational filings. The Commission added, however, that it did not consider the informational rates binding for any future transactions. Accordingly, we need not now prescribe a specific method to calculate the unbundled transmission rate included in informational filings.

Existing Contracts

In the Final Rule, the Commission explained that because it was not abrogating existing requirements and transmission contracts generically and because the functional unbundling requirement applies only to new wholesale services, the terms and conditions of the Final Rule pro forma tariff do not apply to service under existing requirements contracts.[56]

Rehearing Requests

San Francisco asks that the Commission clarify that nothing in Order No. 888 is intended to affect prices, or price-setting methodologies, in existing contracts.

Commission Conclusion

By order issued July 2, 1996, we clarified that

> the filing of an open access compliance tariff on or before July 9, 1996 does not supersede an existing transmission agreement that has been accepted by the Commission unless specifically permitted in the agreement on file. If a utility seeks to modify or terminate an existing transmission agreement, it must separately file to modify or terminate such contracts under appropriate procedures under section 205 or 206 of the Federal Power Act, consistent with the terms of its contract.[57]

Thus, nothing in Order No. 888 affects prices or price-setting methodologies in existing contracts, unless specifically permitted in the contract on file.

6. Flow-based Contracting and Pricing

In Order No. 888, the Commission explained that it would not, at that time, require that flow-based pricing and contracting be used in the electric industry.[58] It recognized that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment. At the same time, however, the Commission noted that contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. Thus, the Commission was concerned that to require a dramatic overhaul of the traditional approach—such as a shift to some form of flow-based pricing and contracting—could severely slow, if not derail for some time, the move to open access and more competitive wholesale bulk power markets. In addition, the Commission indicated its belief that it would be premature to impose generically a new pricing regime without the benefit of any experience with such pricing. Accordingly, the Commission welcomed new and innovative proposals, but determined not to impose some form of flow-based pricing or contracting in the Final Rule.

Rehearing Requests

American Forest & Paper argues that contract path pricing should be prohibited. American Forest & Paper asserts that QFs and other independents are being forced by contract path wheeling utilities to indemnify them from liability for third-party claims of inadvertent flow costs resulting from the transaction, while paying postage stamp rates for the entire amount of contracted transmission. American Forest & Paper supports an average postage stamp rate by region, with the utilities within the region agreeing on a way to divide up the rate appropriately.

Commission Conclusion

As the Commission explained in the Final Rule, we are concerned that a dramatic overhaul of the traditional contract path approach could slow or derail the move to open access and, in any event, is premature without the benefit of any experience with alternative pricing regimes. The Commission, however, welcomes new and innovative proposals from the industry. American Forest & Paper has not presented a case-specific proposal of any detail that would provide the Commission and interested parties the opportunity to test the appropriateness of a change from the contract path approach. Until the Commission has such an opportunity, we are not prepared to change generically the traditional contract path approach with which the electric industry is so familiar.

Moreover, American Forest & Paper's proposal to prohibit contract path pricing and mandate regional postage-stamp rates would be inconsistent with the rate flexibility that the Commission provided in the Transmission Pricing Policy Statement and embraced in the Final Rule.

B. Legal Authority

In the Final Rule, the Commission responded to commenters challenging the Commission's authority to require open access and reaffirmed its conclusion in the NOPR that it has the authority under the FPA to order wholesale transmission services in interstate commerce to remedy undue discrimination by public utilities.[59]

Rehearing Requests

Authority To Order Open Access Tariffs

Union Electric challenges the Commission's authority to require wheeling based on arguments that: (1) the Rule overlooks the fact that the *AGD* case[60] pertained to voluntary actions by the pipelines and the Commission's imposition of open access requirements as a condition on permitting the desired authorizations; (2) the Commission incorrectly treats the *Otter Tail* case;[61] (3) the legislative histories of the NGA and FPA are different and the legislative history of the FPA does not support the Commission's authority to order wheeling; (4) the Commission made prior contrary statements to the U.S.

[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*).

[61] Otter Tail Power Company v. FPC, 410 U.S. 366 (1974) (*Otter Tail*).

Supreme Court [in its opposition to the grant of certiorari to review the *AGD* decision] about the nature of Commission authority to order open access and judicial construction of that authority in *AGD* and *Otter Tail*;'' (5) as a matter of statutory construction, the Commission cannot rely on sections 205 and 206, which are silent as to wheeling, when sections 211 and 212 contain express wheeling provisions; (6) the four relevant cases recognized by the Commission indicate that the Commission may not directly or indirectly order a public utility to wheel or transmit energy for another entity under sections 205 and 206, notwithstanding the Commission's circumscribed ability to order wheeling under sections 211 and 212; (7) prior to the issuance of the Final Rule the Commission, with a full appreciation of the legislative history behind Part II, consistently held that it lacks the authority to order wheeling under FPA Part II; (8) the Rule fails to assign ''considerable importance'' to the Commission's ''longstanding interpretation of the statute in accordance with its literal language;'' and (9) in legislative hearings preceding enactment of EPAct, the Office of the General Counsel acknowledged the limitations on the Commission's wheeling power.

Carolina P&L also challenges the Commission's authority to order open access tariffs, arguing that: (1) *Otter Tail* specifically states: ''So far as wheeling is concerned, there is no authority granted the commission under Part II of the Federal Power Act to order it, * * *''; (2) the *Richmond* and *FPL* cases [62] prohibit the Commission from doing indirectly what it cannot do directly; (3) the *AGD* case does not support the Commission's authority to order open access through the filing of generic tariffs—in *AGD* the Commission's authority was based on voluntary actions by the affected pipelines and there are substantial differences between the NGA and the FPA; (4) the legislative history of EPAct indicates that the Commission does not have the authority to mandate open access and can only order open access if section 211 procedures are followed—citing *NYSEG* and *FPL*; and (5) section 211 limits the Commission's authority to order open access on a generic basis—where a specific statute addresses an issue, a more general statute should not be read in a manner that conflicts with the specific statute.

PA Com argues that the Commission's reliance on *AGD* ''impermissibly expands the limited holding of *AGD*'' and the Commission improperly relied on sections 205 and 206 of the FPA to require open access generically—the Commission only has case-by-case jurisdiction.

VA Com declares that the plain meaning of the FPA and cases interpreting sections 206 and 211 show that the Commission does not have the authority to order industry-wide open access.

FL Com and El Paso argue that the Commission only has limited authority to order wheeling and that the Commission has not made the required findings under section 211.[63]

Group Two Section 205 Filings

Union Electric argues that the requirement that Group 2 Public Utilities make section 205 filings is contrary to the voluntary filing scheme inherent in section 205.

Commission Conclusion

Overview

The fundamental legal question before us is the scope of the authority granted to the Commission in 1935 to remedy undue discrimination in interstate transmission services and whether that authority permits us sufficient flexibility to define undue discrimination in light of dramatically changed industry circumstances, in order to provide electricity customers the benefits of more competitively priced power. In the NOPR and Order No. 888, the Commission comprehensively examined case law and legislative history relevant to our authority to order open access transmission services as a remedy for undue discrimination.[64] We also responded at length in Order No. 888 to arguments that questioned our authority to take this step.[65]

On rehearing, as described above, only a few parties continue to question the Commission's authority. As a general matter their rehearings do not raise any arguments, cases, or legislative history not previously considered, and they do not convince us that our action in Order No. 888 is not within our authority under sections 205 and 206 of the FPA. We therefore reaffirm our determination that we have not only the legal authority, but the responsibility, to order the filing of non-discriminatory open access tariffs if we find such order necessary to remedy undue discrimination or anticompetitive effects.

There are several broad points we wish to emphasize in response to the rehearings that have been filed:

First, there is no dispute that the FPA does not *explicitly* give this Commission authority to order, *sua sponte*, open access transmission services by public utilities. However, the fact remains that the FPA does explicitly require this Commission to remedy undue discrimination by public utilities.[66] The finding of the D.C. Circuit in the AGD case, with regard to sections 4 and 5 of the NGA (which parallel sections 205 and 206 of the FPA), are equally applicable here: the Act ''fairly bristles'' with concerns regarding undue discrimination and it would turn statutory construction on its head to let the failure to grant a general power prevail over the affirmative grant of a specific one.[67]

Second, there also is no dispute that before Congress enacted the FPA in 1935, it rejected provisions that would have explicitly granted the Commission authority to order transmission to *any* person if the Commission found it ''necessary or desirable in the public interest.'' However, the fact that Congress rejected an extremely broad common carrier provision does not limit the remedies available to the Commission to enforce the undue discrimination provisions in the FPA.[68]

Third, entities on rehearing understandably have focused on statements in case law that indicate limits on the Commission's wheeling authority. They particularly focus on certain statements by the Supreme Court in *Otter Tail*. The Commission in Order No. 888 fully addressed and considered all relevant case law of which we are aware, including statements in *Otter Tail* and other court cases indicating limitations on our authority.[69] We do not dispute these statements and we

[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).

[65] FERC Stats. & Regs. at 31,673–79; *mimeo* at 112–129.

[66] *See* FERC Stats. & Regs. at 31,669–70; *mimeo* at 101–03.

[67] 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.

recognize limitations on our authorities. However, the fact remains that none of the cases cited, including Otter Tail, involved the issue of whether this Commission can order transmission as a remedy for undue discrimination and none addressed industry-wide circumstances such as those before us in Order No. 888.

Fourth, while Congress in 1978 gave the Commission certain case-by-case authority to order transmission access by both public utilities and non-public utilities, and broadened this case-by-case authority in 1992, Congress also specifically provided in section 212(e) of the FPA that the case-by-case authorities were not to be construed as limiting or impairing any authority of the Commission under any other provision of law.[70] Indeed, the legislative history of EPAct shows that when Congress amended the section 211–212 wheeling provisions and the section 212(e) savings clause in 1992,[71] it was well aware of arguments regarding the scope of the Commission's wheeling authority as a remedy for undue discrimination under section 206. Whereas Congress in 1992 decided to add a flat prohibition on the Commission ordering direct retail wheeling under any provision of the FPA, it did not add a prohibition on the Commission ordering wholesale wheeling to remedy undue discrimination under section 206. It instead retained and modified the savings clause. The issue before us, therefore, hinges on the scope of authority given to this Commission to remedy undue discrimination, not on the scope of authority given to us in 1978 and 1992.

The Commission is significantly influenced by the decision and case law discussion by the D.C. Circuit in the AGD case. This court opinion contains the most recent and comprehensive discussion of the Commission's legal authority to remedy undue discrimination under NGA provisions that mirror those in the FPA, including the relevant case law concerning the Commission's authority to order transmission under the FPA.[72] The rehearing arguments do not, and we believe cannot, reconcile the AGD court's discussion and findings with a conclusion that the Commission cannot under any circumstances (as these parties advocate) order wheeling under sections 205 and 206 to remedy undue discrimination.

In sum, we believe that the essential question of the Commission's legal authority to impose the requirements of Order No. 888 turns on the flexibility of the Commission's remedial authority under sections 205 and 206 of the FPA to remedy undue discrimination. As was true with respect to the natural gas industry, we acknowledge that Commission precedent for many years nurtured the expectation that we would not, under our authority under the FPA, preclude utilities from using their monopoly power over the nation's transmission systems to secure their monopoly position as power suppliers. However, as described at length in Order No. 888, these policies arose in the context of practical, economic, and regulatory circumstances that gave rise to vertically integrated monopolies and little, if any, competition among power suppliers. In this kind of regime, the interests of customers were most effectively served by the kind of cost-based regulatory regime that has prevailed until very recently. The evolution of third-party generation, facilitated by PURPA and significant technological advances, dramatically altered the economics of power production. The enactment of EPAct recognized these changes and established a national policy intended to favor the development of a competitive generation market, so that the efficiencies of the new marketplace will be available to customers in the form of lower costs for electricity. Utility practices that may have been acceptable a few years ago would, if permitted to continue, smother the fledgling competitive wholesale markets and undermine the efforts of customers to seek lower-price electricity. We firmly believe that our authorities under the FPA not only permit us to adapt to changing economic realities in the electric industry, but also require us to do so, if that is necessary to eliminate undue discrimination and protect electricity customers.

Specific Arguments [73]

The Factual Circumstances Underlying AGD Do Not Mandate A Different Conclusion In This Proceeding

Both Union Electric and Carolina P&L argue that the Commission cannot rely on *AGD* in support of its actions in the electric industry, and they attempt to distinguish the legal basis on which the Commission acted in requiring open access transportation for gas pipelines. Specifically, they argue that AGD (Order No. 436) pertained to *voluntary* actions by gas pipelines and that the Commission's imposition of open access requirements was a *condition* of certificate authorizations to transport gas, whereas the Commission's action in Order No. 888 is a direct mandate.[74] We believe this is a distinction without a difference. While it is true that the Commission required open access as a condition of granting blanket authorizations for pipelines and authorizations for pipelines authorizing pipelines to transport natural gas,[75] the critical point is that in both Order No. 436 and Order No. 888 the Commission's actions hinged as a legal matter on the parallel provisions of the NGA (sections 4 and 5) and the FPA (sections 205 and 206) that prohibit undue discrimination. Whether persons are seeking to transport natural gas or wheel electric power in interstate commerce, by law they must not unduly discriminate or grant undue preference.[76]

In *AGD*, the court upheld the Commission's reliance upon sections 4 and 5 of the NGA to impose an open-access commitment on any pipeline that secured a blanket certificate to provide gas transportation under section 7 of the NGA or provided transportation under section 311 of the NGPA.[77] Order No. 436 was not a simple order that relied on the ''voluntary actions'' of affected pipelines. As the court in *AGD* understood:

> 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.* * *

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[70] *See* FERC Stats. & Regs. at 31,686–87; *mimeo* at 148–49.

[71] 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.

[74] *See* Union Electric and Carolina P&L.

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

[76] 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.

At stake is the role of interstate natural gas pipelines. Although they are obviously transporters of gas, they have until recently operated primarily as gas merchants. They buy gas from producers at the wellhead and resell it, mainly to local distribution companies (''LDCs'') but also to relatively large end users. The Commission has concluded that a prevailing pipeline practice—particularly their general refusal to transport gas for third parties where to do so would displace their own sales—has caused serious market distortions. It has found this practice ''unduly discriminatory'' within the meaning of § 5 of the NGA. Order 436 is its response.

The essence of Order No. 436 is a tendency, in the industry metaphor, to ''unbundle'' the pipelines' transportation and merchant roles. If it is effective, the pipelines will transport the gas with which their own sales compete; competition from other gas sellers (producers or traders) will give consumers the benefit of a competitive wellhead market. [78]

Indeed, since Order No. 436 issued, virtually all jurisdictional natural gas pipelines became ''open access'' transporters of natural gas.

In analyzing the Commission's authority to remedy undue discrimination, the court never made the distinctions now being put forth by Union Electric and Carolina P&L. Rather, the court specifically focused on the Commission's authority under section 5 of the NGA and upheld the Commission's authority to remedy undue discrimination in the transportation of natural gas by requiring pipelines transporting natural gas to do so on a non-discriminatory basis.[79] Similarly, the Commission in Order No. 888 found undue discrimination in the transmission of electric energy and required, pursuant to section 206 of the FPA (the FPA provision that parallels section 5 of the NGA), that if public utilities transmit electric energy in interstate commerce, they must do so on a non-discriminatory basis (*i.e.*, offer non-discriminatory open access transmission).

Moreover, while the Commission may have imposed a ''condition'' on pipelines obtaining blanket certificates or providing section 311 transportation in Order No. 436, this does not detract from the court's core finding in *AGD* that the Commission had the authority under section 5 of the NGA to remedy undue discrimination by requiring open access transportation.[80] The Commission chose in Order No. 436 to impose its open access remedy as a condition to pipelines obtaining a blanket certificate to transport natural gas, but its authority was rooted in the undue discrimination provisions of section 5. Additionally, the practical result of the conditioning was that all jurisdictional pipelines would have to provide open access transportation, a result that was clearly anticipated by the *AGD* court.[81] Thus, there is no distinction in the result intended, or the result achieved, in either industry; in both cases, the intent was to remedy undue discrimination pursuant to the statutes governing each industry, and in both cases the result was that all transporters/transmitters must agree to open access non-discriminatory services if they seek to continue owning, controlling or operating monopoly interstate transportation facilities.

Legislative History Behind the FPA and EPAct Does Not Preclude Our Action

We disagree with the arguments that the legislative history behind Part II of the FPA establishes that the Commission cannot under any circumstance order wheeling under FPA sections 205 and 206.[82] We examined the legislative history of sections 205 and 206 at length in the NOPR and Order No. 888 and concluded that it supports our authority to order open access transmission as a remedy for undue discrimination.[83] We also have examined the legislative history of the EPAct amendments to sections 211 and 212 and conclude that Congress in EPAct did not resolve the issue of our authority under sections 205 and 206 and left untouched whatever pre-existing authorities we had under these sections. The parties have raised nothing new on rehearing to persuade us that our interpretation is wrong. However, there are several arguments that we believe warrant further discussion.

Parties on rehearing argue that the existence of sections 211 and 212 limit the Commission's wheeling authority and, in effect, remove our authority under section 206 to order any transmission as a remedy for undue discrimination.[84] We disagree. In enacting EPAct, Congress did not resolve the extent of our wheeling authority outside the context of sections 211 and 212.[85] As we explained above, while Congress in 1978 gave the Commission certain case-by-case authority to order transmission access, it also specifically provided in section 212(e) of the FPA that the case-by-case authorities were not to be construed as limiting or impairing any authority of the Commission under any other provision of law. Congress retained a similar savings clause when it amended sections 211 and 212 in 1992. Moreover, the legislative history of EPAct shows that when Congress amended sections 211 and 212, it was well aware of arguments regarding the scope of the Commission's remedial authority under section 206.[86] Whereas Congress added an amendment prohibiting the Commission from ordering direct retail wheeling under *any* provision of the FPA, it chose not to add a prohibition on the Commission ordering wholesale wheeling as a remedy for undue

[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.

[81] *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.

[83] 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.

[85] 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.

[86] *See* note 71 and related discussion, *supra*.

discrimination under sections 205 and 206.[87]

We are not persuaded that this conclusion is wrong based on rehearing arguments that we ignored other legislative history of EPAct. Carolina P&L argues that we ignored various statements of Senator Wallop following the enactment of EPAct, which it alleges are counter to our claim of authority to order open access transmission as a remedy for undue discrimination. The utility is simply in error that we ignored these statements. We explicitly mentioned Senator Wallop's statements in Order No. 888 and gave our rationale for why section 211 does not limit our authority to remedy undue discrimination.[88] However, we believe it is important to elaborate on the context in which those statements were made and our interpretation of those statements.

The primary focus of Senator Wallop's statements is on the transmission authority given by the EPAct amendments to sections 211 and 212. These statements emphasize restrictions on our section 211 wheeling authority, including the fact that section 211 does not give the Commission authority to order transmission access on its own motion or to order open access transmission.[89] We do not quarrel with these statements because sections 211 and 212 clearly do place restrictions on our authority to order access under those provisions. The statements also discuss the differences between the House introduced amendments to sections 211 and 212 (which would have provided broader and in some instances mandatory access authority) and the amendments that finally passed (which were more limited). We also do not disagree that changes were made to the bill that originally was introduced. At issue here, however, is not whether there are restrictions on our section 211 authority, but rather whether we have authority *outside the context of section 211* to order transmission as a remedy for undue discrimination. The only statement among Senator Wallop's remarks that addresses this specific issue is one in which he says, ''*In my opinion*, neither the amendments made by this Act *nor existing law* give the FERC any authority to mandate open access transmission tariffs for electrical utilities.'' (emphasis added). We do not view one senator's opinion as in any way dispositive of the issue. As discussed *supra*, when Congress enacted the 1992 section 211 amendments it was well aware of the outstanding legal issue of the Commission's authority to order access as a remedy for undue discrimination under section 206. It chose not to clarify this issue by prohibiting the Commission from ordering access, but instead retained the savings clause in section 212(e).

The issue of our legal authority thus turns on the undue discrimination authority given to us in 1935, and the legislative history of sections 205 and 206. We discussed this at length in Order No. 888.[90] On rehearing, several entities emphasize the *Otter Tail* case and the legislative history referred to in that case. In particular, Union Electric recites Justice Stewart's discussion of the legislative history in his partial dissent in *Otter Tail*. We do not interpret that discussion to suggest that we do not have the authority to remedy undue discrimination by requiring open access transmission under any circumstance. As we explained in Order No. 888:

> In the FPA, while Congress elected not to impose common carrier status on the electric power industry, it tempered that determination by explicitly providing the Commission with the authority to eradicate undue discrimination—one of the goals of common carriage regulation. By providing this broad authority to the Commission, it assured itself that in preserving ''the voluntary action of the utilities'' it was not allowing this voluntary action to be unfettered. It would be far-reaching indeed to conclude that *Otter Tail*, which was a civil antitrust suit that raised issues entirely unrelated to our authority under section 206, is an impediment to achieving one of the primary goals of the FPA—eradicating undue discrimination in transmission in interstate commerce in the electric power industry. [91]

In response to Union Electric's arguments that Congress explicitly rejected common carrier provisions in 1935, we do not disagree with Union Electric's statement that ''the mandatory wheeling language was not dropped inadvertently.'' [92] The point that we made in Order No. 888 (quoting *AGD*) in this regard was that

> (1) ''Congress declined *itself* to impose *common carrier* status'' (emphasis added) and (2) there is no ''support for the idea that the Commission could under no circumstances whatsoever impose obligations encompassing the core of a common carriage duty.'' [93]

Nowhere did we ever suggest that the mandatory wheeling language was dropped inadvertently; we simply distinguish a general common carrier obligation imposed ''in the public interest'' from an obligation to provide transmission service deemed necessary to eliminate undue discrimination. Finally, we fully agree with Union Electric's statement that

> [a]lthough this ''first Federal effort'' occurred in 1935, the resulting FPA Sections 205 and 206 have not been modified in any relevant respect since that time. Therefore, the range of authority conveyed to the Commission in such sections remains the same today as it did then. [94]

We never suggested otherwise and our conclusion in Order No. 888 is not based on a finding to the contrary.

Case Law Does Not Prohibit Our Ordering Wheeling Under Sections 205 and 206 of the FPA

Union Electric, discussing the very cases cited by the Commission in Order No. 888, asserts that ''the Commission fails to recognize their dispositive results prohibiting it from ordering wheeling under the Sections 205 and 206 of the FPA.'' [95] We thoroughly examined all of the case law cited by Union Electric, as evidenced by our discussions in the NOPR and Order No. 888, and disagree that any of those cases prohibit the Commission from ordering wheeling under sections 205 and 206 of the FPA to remedy undue discrimination. Indeed, the *AGD* court reached the same conclusion.[96]

Union Electric further cites to a variety of FPC cases that it claims demonstrate that the Final Rule exceeds the Commission's statutory authority.[97] It appears to have proffered every negative Commission statement it could find with respect to our authority to order wheeling under Part II of the FPA.

[87] 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.

[96] 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.

As in the Commission cases cited, we recognize that our authority to order transmission service is not unbounded; if we order transmission, it must be within the scope of authority available to us under the FPA. However, the fact is that none of the cases cited as establishing limits on the Commission's authority addresses the issue before us now, *i.e.*, the Commission's authority to order transmission as a remedy for undue discrimination. Simply stated, the Commission has never before been faced with generic findings of undue discrimination in the provision of interstate electric transmission services, and the extent of its authority to remedy that undue discrimination.

The Commission's General Counsel Never Asserted, or Even Suggested, That the Commission Does Not Have the Authority to Order Wheeling as a Remedy for Undue Discrimination

Union Electric spends several pages of its rehearing request asserting that the Commission's own General Counsel has acknowledged the limitations on the Commission's authority to order wheeling.[98] In particular, it points to a statement by a Commission OGC witness that ''if Congress intends for the Commission to be able to deal with transmission on its own motion and thereby go further than simply dealing with industry proposals,'' Congress would need ''to include an affirmative statement somewhere in the Act that the Commission could require wheeling on its own motion.''[99] This same statement was previously raised by EEI and previously addressed in Order No. 888. We do not disagree that this statement was made. However, it must be read in the context of the witness' entire testimony in which the witness stated *four* times the view that the case law supports the argument that the Commission has authority to order wheeling as a remedy for undue discrimination.[100] Indeed, contrary to Union Electric's assertion, the extensive legal analysis set forth by the Commission's witness supports the position relied upon in this proceeding.[101] Thus, viewed in the context of the witness' entire testimony, Union Electric's arguments to the contrary are unavailing. Moreover, nowhere did the witness ever suggest, as asserted by Union Electric, that FPA sections 205 and 206 could only be used ''to eliminate unduly discriminatory terms in a wheeling arrangement voluntarily filed with the Commission.''[102]

The Commission Has the Authority to Order Public Utilities to Make Rate Filings in This Proceeding

We reject Union Electric's argument that our requirement that Group 2 Public Utilities make section 205 filings is contrary to the voluntary filing scheme inherent in section 205. It is true that the Commission ordinarily cannot require a utility to make a section 205 filing. However, in this situation the section 205 filing was required as a remedy under section 206 of the FPA to establish rates for non-discriminatory open access transmission. Acting pursuant to section 206 of the FPA, we found that undue discrimination exists in the wholesale transmission of electric power and ordered the filing of non-discriminatory open access transmission tariffs to remedy this discrimination. Section 206 further requires that upon such a finding the Commission ''shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force. * * *'' Thus, we had the authority to set the rates that would be observed and in force following the effectiveness of open access transmission and initially proposed to set rates for each public utility. However, rather than take this intrusive approach, which necessarily would have required a number of generic assumptions and resulted in less than public utility-specific rates, upon issuance of the Final Rule, we chose to permit these public utilities to make section 205 filings to propose their own rates for the services provided in the pro forma tariff.

The Commission's Prior Failure to Order Wheeling as a Remedy for Undue Discrimination Is Not Dispositive

After discussing several cases that it asserts address the Commission's authority to remedy undue discrimination, Carolina P&L declares that ''[p]erhaps the strongest evidence that the Commission lacks the power to compel wheeling under FPA section 206 is the fact that the Commission has never previously exercised this alleged power, despite numerous opportunities to do so.''[103] However, the court in *AGD* succinctly dismissed a similar argument:

> It is finally argued that the Commission's not having imposed any requirements like those of Order No. 436 in the period from enactment in 1938 until the present demonstrates the lack of any power to do so. * * * But as our introductory review of the economic background sought to illustrate, the Commission here deals with conditions that are altogether new. Thus no inference may be drawn from prior non-use.[104]

Undue Discrimination/Anticompetitive Effects[105]

A number of utilities and state commissions argue that the Commission lacks evidence to support a finding of undue discrimination.[106]

VA Com argues that the Commission failed to make a legally supportable finding of industry-wide undue discrimination: ''FERC apparently drew a conclusion that there was undue discrimination in the NOPR without support and later accepted customers' allegations, without further inquiry, and relied on them in making its finding of industry-wide undue discrimination.'' (VA Com at 2–3).

PA Com and Carolina P&L assert that allegations of undue discrimination do not form a sufficient basis to compel a generic rulemaking. Not coming forward with specific accusations and the identity of specific accusers, PA Com asserts, is unconstitutional as a deprivation of due process.

[98] Union Electric at 37–40.

[99] Union Electric at 38–39.

[100] 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.'').

[101] 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.

[102] 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.

With regard to specific allegations of undue discrimination, SoCal Edison argues that the Commission inappropriately relied upon allegations involving SoCal Edison as evidence of undue discrimination. SoCal Edison asks that the Commission declare that it is not making a factual determination as to any particular allegation especially since prior to 1994 the Commission defined discrimination differently. Dalton similarly argues that the Commission has no basis for finding that Georgia Power Company is engaged in unlawful undue discrimination as to new or roll-over transmission services in the operation of the Integrated Transmission System in Georgia (ITS) under the ITS agreement. Moreover, Dalton argues, even if it is found that GPC acted in unduly discriminatory manner, it is not practical or lawful to order open access tariff for new and roll-over services.

Finally, Carolina P&L argues that the comparability standard does not eliminate the ''requirement'' that parties must be similarly situated before discrimination is present, and that the Commission has not provided factual support for its implicit finding that public utilities and their native load customers are similarly situated to third parties. It cites *City of Vernon* v. *FERC*, 845 F.2d 1042 at 1045–46 (D.C. Cir. 1988), in support.

Commission Conclusion

As an initial matter, the Commission grants SoCal Edison's request for clarification that in Order No. 888 we did not make a factual determination as to any particular allegation of past discrimination described in the Final Rule.[107] However, we reject arguments that the Commission cannot rely in part on the array of allegations and circumstances raised by customers in individual cases over the years and brought forth in response to the NOPR. The specific allegations are illustrative. However, they present examples of the types of discriminatory incentives and behavior inherent in ownership of monopoly transmission facilities, and also present credible examples of the types of discriminatory behavior in which public utilities could engage in the future. We also reject arguments that customers and the Commission must litigate and make specific findings of discrimination against each public utility before we can take any action to preclude discriminatory behavior that will harm competition and, ultimately, electricity consumers. This is particularly true where the discriminatory behavior clearly is in the economic self-interest of a monopoly transmission owner facing the markedly increased competitive pressures that are driving today's electric utility industry. As we recognized in Order No. 888,

> [t]he inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation, and it is our duty to eradicate unduly discriminatory practices. As the AGD court stated: ''Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [108]

We believe that the same general discriminatory circumstances that faced us when we required open access transportation in the natural gas industry [109] are also before us today in the electric industry. First, it is uncontested that market power continues to exist in the ownership and operation of the monopoly-owned facilities that comprise the nation's interstate transmission grid. Second, utilities, as a general matter, did not in the past offer comparable transmission services to competitors or to customers. Open access services simply were not made available by utilities until the late 1980s when the Commission began to impose open access as a condition of approval of market-based rates and utility mergers in order to mitigate market power and remedy anticompetitive effects. Rather, the vast majority of utilities historically have declined to transport electric energy that would compete with their own sales or have offered access that is inferior to what they use for their own sales. Third, discrimination in transmission services, when viewed in light of utilities' own uses of their transmission systems compared to what they offer third parties, has denied and will continue to deny customers access to electricity at the lowest reasonable rates. The entities on rehearing have raised nothing to persuade us that it is in the interests of consumers to maintain the self-evident incentives for transmission owners to exercise their monopoly power over transmission to discriminate in favor of their own generation sales—incentives that will only increase in the future as competitive pressures continue to escalate.

The Commission addressed the same argument as that being made by Carolina P&L, that the Commission has not made the requisite finding that third-party transmission customers are similarly situated to public utilities and their native load customers, in 1994 in the *NEPOOL* and *AEP* cases.[110] In these cases, we recognized that the traditional focus of our undue discrimination analysis had been whether factual differences justify different rates, terms and conditions for similarly situated customers, but concluded that due to changing conditions in the electric utility industry, it was necessary to reevaluate our traditional analysis. As we stated in *NEPOOL*, the focal point of undue discrimination claims has shifted from claims of undue discrimination in rates and services which the utility offers different customers to claims of undue discrimination in rates and services which the utility offers when compared to its own use of the transmission system.[111] ''In this context, framing the analysis in terms of how a public utility treats similarly situated customers is not applicable or instructive.'' [112] The Commission concluded that it therefore must reexamine its application of the standard for undue discrimination claims under sections 205 and 206 of the FPA.

The Commission further elaborated on its re-examination of undue discrimination in *AEP*. The Commission cited its *NEPOOL* discussion and set for hearing the different uses that AEP made of its transmission system and whether there were any operational differences between any particular use that AEP made of the system and the use third parties might need, and, in particular, the degree of flexibility AEP accorded itself in using its transmission system for different purposes. The Commission subsequently set the same issue for hearing in several other cases.[113] In the NOPR, however, the Commission concluded that based on what it had learned in the ongoing cases, it would address this issue generically in this rulemaking. We announced in the NOPR our belief that

[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).

[111] 67 FERC ¶ 61,042 at 61,132.

[112] *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)

all utilities use their own systems in two basic ways: to provide themselves point-to-point transmission service that supports coordination sales, and to provide themselves network transmission service that supports the economic dispatch of their own generation units and purchased power resources (integrating their resources to meet their internal load). Third parties may need one or both of these basic uses in order to obtain competitively priced generation or to have the opportunity to be competitive sellers of power, and the Commission proposed that all public utilities must offer both services on a non-discriminatory open access basis.[114]

We affirmed this determination in the Final Rule. We concluded that a public utility must offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others. Because a public utility that is reasonably capable of providing transmission services may provide itself such services at any time it finds those services desirable, it is irrelevant that it may not be using or providing that service today.[115] Thus, based on the analysis in this record, the Commission has determined that undue discrimination in the provision of transmission services in today's industry does not turn on whether utilities and their native load customers are similarly situated to third parties, but instead turns on whether the utility is providing comparable service, that is, service that it is reasonably capable of providing to other users of the interstate transmission system.

In short, the Commission is not bound to a static application of its undue discrimination analysis under the FPA and, indeed, has a public interest responsibility to reexamine undue discrimination in light of changed circumstances in the industry.[116] That is what we began in *NEPOOL* and *AEP* and have completed in this rulemaking. The traditional ''similarly situated'' test, while applicable to discrimination among third-party customers, simply is not applicable when analyzing discrimination between third-party transmission customers and transmission owners. Under Carolina P&L's theory, presumably the only customers that could be shown to be similarly situated would be those who own monopoly transmission facilities and have native load (*i.e.*, captive) customers. This would preserve customer captivity, perpetuate monopoly power and profits, and deny the lowest reasonable rates to consumers. We therefore reject Carolina P&L's arguments.

Moreover, the fact that public utilities and their native load customers have been treated differently from third-party transmission customers because they are not among those traditionally considered to be ''similarly situated'' is precisely the target at which Order No. 888 takes aim. Historically, competitively-priced power was not broadly available to wholesale customers because the industry was dominated by vertically integrated IOUs[117] and, to the extent cheaper generation alternatives were available in the marketplace, transmission owners either took the cheaper power for their own uses or purchased and re-sold it at a profit.[118] Prior to EPAct, most power customers took power from the vertically integrated utilities that provided their transmission service. Transmission-only transactions played a secondary role in bulk power markets, facilitating certain economy transactions and coordination and pooling arrangements that improved utility operational efficiencies, largely as a complement to bundled bulk power transactions. Given the predominantly vertically-integrated industry and efficiencies that could be gained through encouragement of coordination and pooling transactions, the Commission was willing to accept utility practices that provided third parties with transmission services that were distinctly inferior to the utility's own uses of the transmission system.

In the future, however, unbundled transmission service will be the centerpiece of a freely traded commodity market in electricity, in which all wholesale customers can shop for power. In a market characterized by a significant increase in non-vertically integrated power suppliers and competitively priced power that is now meaningfully available, it is no longer in the interest of wholesale customers for the Commission to tolerate the types of practices that were previously accepted. We cannot allow what have become unduly discriminatory practices to erect barriers between customers and the rapidly emerging competitive electricity marketplace. Accordingly, a primary goal of Order No. 888 is to provide that in the future transmission providers and third-party transmission customers are ''similarly situated'' in the quality of transmission service available to them.

C. Comparability

1. Eligibility to Receive Non-discriminatory Open Access Transmission

In the Final Rule, the Commission modified the definition of ''eligible customer'' and, among other things, clarified that any entity engaged in wholesale purchases or sales of electric energy, not just those ''generating'' electric power, is eligible.[119] The Commission also clarified that entities that would violate section 212(h) of the FPA (prohibition on Commission-mandated wheeling directly to an ultimate consumer and sham wholesale transactions) are not eligible. Further, the Commission clarified that foreign entities that otherwise meet the eligibility criteria may obtain transmission services. The Commission also provided for service to retail customers in circumstances that do not violate FPA section 212(h). Persons that would be eligible section 211 applicants also would be eligible under the open access tariff.

a. Unbundled Retail Transmission and ''Sham Wholesale Transactions''

Rehearing Requests

Several entities assert that there is an inconsistency between tariff language and preamble language and argue that section 1.11 of the tariff should be made consistent with the preamble to ensure that, absent a state-approved program, retail wheeling is not available under the tariff, no matter which party requests service.[120] They maintain that the limitation in section 1.11 that the transmission provider only must provide retail transmission service voluntarily or under a state-approved program appears to apply only when a retail customer is the purchaser, not when the transmission purchaser is an electric utility. They suggest the

[114] 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.

[118] 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.

following language to remedy the problem: ''however, such entity is not eligible for transmission service that would be prohibited by Sections 212(h)(1) and/or 212(h)(2) of the Federal Power Act, unless such service is provided pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Transmission Provider.'' (PSE&G at 22; Carolina P&L at 8–9).

Detroit Edison argues that the Commission should modify the definition to exclude any reference to transmission service provided to retail customers so as to avoid confusion and possible forum shopping. At the least, Detroit Edison argues, the Commission should modify the language to state that transmission service is available to an ultimate consumer to the extent, and only to the extent, that the service is authorized by a lawful state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the transmission provider.

NYSEG asserts that the Commission did not apply the section 212(h) limitation to service to retail customers under the tariff. NYSEG requests that the Commission clarify that it will not require retail wheeling beyond the scope of state-mandated retail access programs or beyond the terms of a transmission provider's voluntary offer of retail wheeling service.

Oklahoma G&E asks the Commission to clarify that the term eligible customer differentiates between a customer eligible to receive transmission service and a customer whose transaction is a sham or would result in mandatory retail wheeling and would therefore be prohibited by section 212(h).

NYSEG further asserts that the right of first refusal provision would permit a retail customer receiving wheeling service to continue to take that service upon expiration of its contract, which could require the transmission provider, in violation of section 212(h), to continue retail wheeling beyond the scope of its voluntary offer of service or beyond the scope of a state-mandated retail access program.

SoCal Edison argues that the Commission cannot compel a utility to supply retail transmission service if the utility challenges the authority of the state to require retail wheeling and section 1.11 should be revised to reflect this.

IL Com declares that it ''does not recognize FERC's claim of jurisdiction over retail transmission service provided directly to a retail customer and disputes that unbundled retail wheeling directly to a retail customer is a service provided in interstate commerce.'' (IL Com at 35). Thus, ''if FERC's proposed 'deference' to states is to be given any effect, states must be allowed to determine whether the retail transmission component of the retail wheeling program will be provided pursuant to the utility's existing filed wholesale tariff or whether the retail transmission will be provided pursuant to a 'separate retail transmission tariff' that is different from the wholesale tariff.'' (IL Com at 36). IL Com concludes that it is inappropriate (and illegal if FERC is overturned on its retail transmission jurisdiction assertion) to include retail customers taking final delivery of unbundled power for their own end uses under retail wheeling programs as eligible customers.

PA Com argues that it is relevant whether a customer is receiving retail or wholesale service and redefining transmission and local distribution service does not automatically convey jurisdiction to the Commission.

CCEM asks that the Commission clarify that a retail customer eligible to seek transmission service should be able to seek transmission service not only from the transmission provider, but from any other transmission provider. CCEM also asks that the Commission add the word ''ultimate'' before the word transmission provider in section 1.11 of the tariff.

EEI asks the Commission to ''clarify that the transmission service provider should be allowed to supplement the terms and conditions of the pro forma tariff with additional provisions that specifically relate to the *totality* of the transmission service being provided, including the use of distribution facilities and any other transmission facilities not currently included in wholesale rates.'' (EEI at 24 (emphasis in original)).[121]

Union Electric argues that a literal reading of the eligibility definition could require retail wheeling by utilities in states other than those required to participate in a particular retail wheeling program.

Commission Conclusion

The Commission agrees with those entities that argue that section 1.11 of the pro forma tariff does not explicitly prohibit ''sham wholesale transactions'' that could currently be arranged under the tariff by a utility applying for service and designating the retail customer as a point of delivery. We therefore have modified section 1.11 to clarify that, with respect to service that we are prohibited from ordering by section 212(h) of the FPA (whether direct retail wheeling or ''sham'' wholesale wheeling), otherwise eligible entities may obtain such service under the tariff only if it is pursuant to a state requirement that such service be provided or pursuant to a voluntary offer of such service. We also have modified the language to clarify that eligibility for unbundled direct retail service required by a state applies only to service from transmission providers that the state orders to provide the service. The modified language states:

Eligible Customer: (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an eligible customer under the tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada, or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider. (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an eligible customer under the tariff.

Regarding SoCal Edison's argument, the Commission stated in the Final Rule:

Moreover, we are mindful of the fact that we are precluded under section 212(h) from ordering or conditioning an order on a requirement to provide wheeling directly to an ultimate consumer or sham wholesale wheeling. We therefore clarify that our decision to eliminate the wholesale customer eligibility requirement does not constitute a requirement that a utility provide retail transmission service. Rather, we make clear that if a utility chooses, or a state lawfully requires, unbundled retail transmission service, such service should occur under this tariff unless we specifically approve other terms.[122]

Therefore, the Commission is not compelling a utility to provide unbundled retail transmission service.[123] Rather, the Commission requires that

[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

Continued

should such service be provided, either pursuant to state mandate or voluntarily, it must be provided pursuant to the pro forma tariff unless the Commission approves alternative terms and conditions.

However, in light of CCEM's request that we clarify that a retail customer eligible to seek transmission service under the tariff should be able to seek service not only from the transmission provider, but also from any other transmission provider, and in light of Union Electric's concerns regarding retail service eligibility, we believe certain clarifications of our jurisdiction and of the statements made in Order No. 888 are necessary. The statements cited above that were made in Order No. 888 and the eligible customer tariff definition in (ii) above refer to direct retail transmission, *i.e.,* the transmission of electric energy ''directly'' to an ultimate consumer. The Commission is prohibited by section 212(h)(1) of the FPA from ordering this type of retail transmission and that is why customers are eligible for such transmission under the tariff only if the transmission is pursuant to a state order or is provided voluntarily. However, on its face, section 212(h) does not prohibit the Commission from ordering public utilities to provide ''indirect'' unbundled retail transmission in interstate commerce, *i.e.,* the transmission necessary to transmit unbundled electric energy to a utility that ultimately will deliver the energy to a customer that is purchasing the unbundled energy at retail either pursuant to a state retail access order or pursuant to voluntary delivery by the local utility.

We clarify that we believe we have the jurisdiction under the FPA to order indirect retail transmission to an ultimate consumer and that if the Commission under sections 205, 206 or 211 of the FPA orders such transmission, entities that otherwise qualify as eligible customers under the tariff will take transmission service for such indirect retail wheeling pursuant to the pro forma tariff. We note that the Commission may order such transmission on a case-by-case basis or may determine to do so generically in the future. We expect public utilities to provide such indirect retail access under the pro forma tariff and, if they do not, we will not hesitate to order them to do so.

In response to IL Com's argument that it does not recognize this Commission's claim of jurisdiction over the rates, terms and conditions of unbundled retail transmission that is provided directly to an ultimate consumer, the Commission reaffirms its legal conclusion set forth in the Final Rule.[124] As to its claim that we should give deference to the state as to whether such service could be taken under the wholesale tariff or a separate retail tariff on file with the Commission, we reaffirm our conclusion to address this on a case-by-case basis. Since the Final Rule issued, the Commission has addressed this in several orders. In *New England Power Company,* the Commission stated: [125]

As we explained in the Open Access Rule and in the New Hampshire Interim Order, we generally expect retail transmission customers to take service under the same Commission tariff that applies to wholesale customers. While we generally will defer to state requests for a separate retail tariff to accommodate the design and special needs of a state retail access program, the Massachusetts Commission has made no such request in this case. [15]

Subsequently, in *New England Power Company,* 76 FERC ¶ 61,008 (1996), the Commission granted a limited waiver of the Open Access Rule requirements for the New Hampshire retail electric competition pilot project. Specifically, the Commission waived the requirement for individual service agreements, and the requirement for customer deposits. The Commission further announced that:

other public utilities that provide unbundled retail service under a *pro forma* tariff do not need to apply to retail customers the tariff provisions regarding individual service agreements or customer deposits, unless a state retail program so requires. [[126]]

Concerning EEI's request for clarification, the Commission stated in the Final Rule:

all tariffs need not be ''cookie-cutter'' copies of the Final Rule tariff. Thus, under our new procedure, ultimately a tariff may go beyond the minimum elements in the Final Rule pro forma tariff or may account for regional, local, or system-specific factors. The tariffs that go into effect 60 days after publication of this Rule in the Federal Register will be identical to the Final Rule pro forma tariff; however, public utilities then will be free to file under section 205 to revise the tariffs, and customers will be free to pursue changes under section 206.[127]

Utilities are free to include customer-specific terms and conditions or terms and conditions limited to certain customers (*e.g.,* a distribution charge) in the customer's service agreement and/or the network customer's network operating agreement.

b. Transmission Providers Taking Service Under Their Tariff

Rehearing Requests

TAPS states that section 1.11 does not seem to require a transmission provider to take service for its purchases, but the preamble does (citing *mimeo* at 57, 191, 266 and regulatory text in section 35.28(c)(2)). It argues that transmission providers should be required to treat their own usage of the transmission system to serve retail customers under the network service provisions of the tariff. TAPS argues that this result could be achieved through an ISO or by requiring transmission providers to abide by all non-price terms of Parts I and III of the tariff. TAPS also argues that the rates charged network customers must be developed on the same basis as the transmission component of retail rates. It states that the transmission provider's purchases would then be made under Part III of the tariff to the extent they are made for serving retail customers. It further asserts that the Commission's authority and obligation to consider transmission owners' service to retail load in establishing wholesale transmission rates has been long established. At the least, TAPS argues that the Commission should require that a transmission provider take its wholesale purchases under some tariff.

Similarly, Coalition for Economic Competition asks the Commission to clarify that the requirement to use the pro forma tariff for wholesale purchases and to functionally unbundle wholesale purchases and sales does not apply to purchases made solely to serve retail customers on a bundled basis. It asserts that there is conflicting language in Order No. 888 (citing *mimeo* at 191) and Order No. 889 (citing *mimeo* at 12) and the pro forma tariff. Coalition for Economic Competition asserts that the Commission does not have jurisdiction over transmission that is part of a bundled retail sale.

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.

[125] 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.

Commission Conclusion

Several parties have noted on rehearing that there is conflicting language among the Final Rule, Order No. 889 and the pro forma tariff as to whether and to what extent the transmission provider must take service for ''wholesale purchases'' under its own tariff. As discussed below, we clarify that a transmission provider does not have to ''take service'' under its own tariff for the transmission of power that is purchased on behalf of bundled retail customers.

In a situation in which a transmission provider purchases power on behalf of its retail native load customers, the Commission does not have jurisdiction over the transmission of the purchased power to the bundled retail customers insofar as the transmission takes place over such transmission provider's facilities,[128] and therefore the pro forma tariff does not have to be used for such transmission. Moreover, we recognize that purchases made collectively on behalf of native load [129] cannot necessarily be identified as going to any particular customer. However, the Commission does have jurisdiction over transmission service associated with sales to any person for resale, and such transmission must be taken under the transmission provider's pro forma tariff. [130]

Order No. 888, relying on the principle of comparability, established the terms and conditions for network service provided to network customers under the pro forma tariff. Network customers may include the transmission provider itself as well as any other entity receiving Network Integration Service. If the transmission provider purchases energy from another power supplier in order to make sales to its wholesale native load customers, it must take the transmission service necessary to transmit the power from its point(s) of receipt to its point(s) of delivery under the same terms and conditions as other Network Customers.[131] As we explained in *AES Power, Inc.*, network customers are entitled to make economy energy purchases from non-designated network resources at no additional charge on a basis comparable to the economy energy purchases made by the transmission provider on behalf of its bundled retail customer.[132] This applies to the transmission provider as a network transmission customer under its own tariff as well as to other network transmission customers that make economy energy purchases on behalf of their customers. Thus, insofar as all wholesale transmission customer usage is concerned, third-party network customers are treated the same as the transmission owner.

2. Service that Must be Provided by Transmission Provider

In the Final Rule, the Commission found that a public utility must offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others. [133] The Commission explained that because a public utility that is reasonably capable of providing transmission services may provide itself such services at any time it finds those services desirable, it is irrelevant that it may not be using or providing that service today. However, the Commission explained that if a customer seeks a customized service not offered in an open access tariff, a customer may, barring successful negotiation for such service, file a section 211 application.

Rehearing Requests

Cleveland requests that the Commission make explicit that comparability will be evaluated not only by reference to a transmission provider's wholesale services, but also by comparison to the terms, conditions, and prices applicable to its retail services, whether bundled or unbundled. Cleveland asserts that this is needed so that TDUs are not at a competitive disadvantage in competing with the transmission provider for retail customers. It maintains that this is consistent with the Transmission Pricing Policy and established precedent.

Commission Conclusion

No clarification is necessary. In determining what transmission services a utility must offer for wholesale sales of electric energy in interstate commerce, the Final Rule explicitly states that ''a public utility must offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others.'' [134] Further, the Final Rule requires that network service customers receive service comparable to the service provided to the transmission provider's native load. Because the Rule applies to retail transmission that is voluntarily offered or pursuant to a state retail access program, the requirements to offer services that the utility is reasonably capable of providing and services comparable to those provided to native load would also apply to retail service in these limited retail circumstances.

3. Who Must Provide Non-discriminatory Open Access Transmission

In the Final Rule, the Commission explained that its authority under sections 205 and 206 of the FPA permits it to require only public utilities to file open access tariffs as a remedy for undue discrimination.[135] The Commission further explained that it has no authority under those sections of the FPA to require non-public utilities to file tariffs with the Commission.

The Commission also discussed three mechanisms that would help alleviate the problems associated with not being able to require non-public utilities to provide open access: (1) Broad application of section 211; (2) the reciprocity requirement set forth in the Final Rule; and (3) the formation of RTGs.

The Commission also indicated that it will not allow public utilities that jointly own interstate transmission facilities with non-jurisdictional entities to escape the requirements of open access. Thus, the Commission required each public utility that owns interstate transmission facilities jointly with a non-jurisdictional entity to offer service over its share of the joint facilities, even if the joint ownership contract prohibits service to third parties. The Commission required the public utilities, in a section 206 compliance filing, to file with the Commission, by December 31, 1996, a proposed revision (mutually agreeable

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

[129] 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.

[130] 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.

[132] 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.

or unilateral) to their contracts with non-jurisdictional owners.

Rehearing Requests

Jointly-Owned Facilities

Union Electric argues that the Final Rule improperly requires a public utility to unilaterally file a modification to agreements that a non-jurisdictional entity opposes, which amounts to a litigation coercion provision. Union Electric notes that it has been told by Associated Electric Cooperative, Inc. that it will oppose any modifications to Union Electric's agreements. Union Electric further states that these facilities are not commonly owned, but rather each party wholly owns its segment of the facilities.

Dalton asserts that Georgia Power Company cannot comply with the requirement to offer service over its share of joint facilities because the ITS is not owned by members as tenants in common, but instead each member owns specific segments of the transmission grid. Dalton further argues that it is unjust and unreasonable to require Georgia Power Company to give access to the ITS to new and roll-over transmission customers under the Order No. 888 tariff that are unwilling to accept an investment responsibility and an obligation to make balancing payments.

Associated EC argues that the Commission may modify non-jurisdictional contracts only under section 211 of the FPA; the Commission cannot simply modify the contract with respect to the public utility.

NE Public Power District states that it is party to an agreement with a public utility involving jointly constructed transmission facilities that prohibits use of the transmission capacity by a non-party. It asserts that ''[t]he District's contractual rights under its contract constitute valuable property, and the summary annulment of those rights constitutes a violation of Due Process.'' (NE Public Power District at 18–20). Moreover, it argues that blanket invalidation of the terms and conditions of the contracts is contrary to the *Sierra-Mobile* doctrine.

Commission Conclusion

We reject those arguments that maintain that the Commission cannot properly require a public utility to file unilaterally a modification to agreements concerning joint transmission facilities that a non-jurisdictional entity opposes. It is without question that the Commission has the exclusive authority to regulate public utilities engaged in the sale for resale and/or transmission of electric energy in interstate commerce to assure that rates, terms and conditions are just and reasonable and not unduly discriminatory. The fact that a public utility may jointly own, with a non-jurisdictional entity, transmission facilities through which it engages in sales for resale and/or transmission of electric energy in interstate commerce does not alter the Commission's authority to regulate that public utility.[136] If the Commission finds that a matter needs to be remedied, it may issue an order directed at the public utility. The fact that such an order may affect a non-jurisdictional joint owner does not undermine the validity of the Commission's order.[137] Otherwise, a public utility could simply enter into joint agreements with non-jurisdictional utilities to the frustration of the Commission's mandate to protect consumers from undue discrimination.[138]

Nor does the exercise of the Commission's powers under the FPA to remedy undue discrimination by public utilities constitute a violation of due process vis-a-vis the non-jurisdictional entity. When the contract was entered into and filed with the Commission it was with the explicit knowledge that the Commission could regulate the rates, terms and conditions of the contract with respect to the jurisdictional services provided thereunder by the public utility. If and when a public utility unilaterally files either to amend or terminate the agreement, the non-jurisdictional party is free to raise any arguments it wishes to support its position that no changes are necessary to ensure that the contract is just and reasonable and not unduly discriminatory or preferential.

4. Reservation of Transmission Capacity by Transmission Customers

In the Final Rule, the Commission concluded that firm transmission customers, including network customers, should not lose their rights to firm capacity simply because they do not use that capacity for certain periods of time.[139]

[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.

[137] Though the non-jurisdictional entity would not become subject to Commission regulation.

[138] 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.

Rehearing Requests

No rehearing requests addressed this matter.

5. Reservation of Transmission Capacity for Future Use by Utility

In the Final Rule, the Commission concluded that public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon.[140] However, the Commission determined that any such capacity that a public utility reserves for future growth, but is not currently needed, must be posted on the OASIS and made available to others through the capacity reassignment requirements, until such time as it is actually needed and used.

Rehearing Requests

CCEM argues that it is discriminatory to allow public utilities and network transmission customers to reserve existing transmission capacity for their native load growth because it (1) limits the determination of ATC, (2) is likely to increase the cost of transmission for other customers, and (3) is inconsistent with a capacity reservation-based system. CCEM argues, however, that if the reservation feature is retained, franchise utilities that reserve capacity must pay the full reservation charges, with no cost shifting to other customers. CCEM further recommends that all reservation payments should be credited directly to firm transmission services and the planning horizon should be limited to a reasonable time into the future.

American Forest & Paper argues that to achieve comparability, utilities must not be permitted to withhold capacity from the market for the benefit of native load. American Forest & Paper further argues that the Commission must establish mechanisms for evaluating the reasonableness of the utilities' requirements and projections, otherwise they have an incentive to over-forecast and to extend their planning horizons. American Forest & Paper suggests that requiring utilities to establish separate entities to purchase transmission on behalf of their native load would help solve this problem.

VA Com requests that the Commission clarify what will happen if a utility's forecast of load growth is too low. It argues that native load should not have to bear the burden of any forecast errors and that utilities should be required to reserve sufficient capacity to serve the current and projected needs

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

of native load customers. VA Com would also have the definition of native load in section 1.19 of the tariff expanded to include existing distribution cooperatives and others who currently provide service to end users. With respect to reservation priority, VA Com states that the Commission should establish the following reservation priority: native load customers, firm contract customers, and non-firm customers. Finally, VA Com asserts that the calculation of ATC must not include any capacity that may be needed by native load customers.

Commission Conclusion

We will deny the requests of CCEM and American Forest and Paper. We continue to believe that public utilities should be allowed to reserve existing transmission capacity needed for native load growth and network customer load growth reasonably forecasted within the utility's current planning horizon.

We note that network service is founded on the notion that the transmission provider has a duty to plan and construct the transmission system to meet the present and future needs of its native load and, by comparability, its third-party network customers. In return, the native load and third-party network customers must pay all of the system's fixed costs that are not covered by the proceeds of point-to-point service. This means that native load and third-party network customers bear ultimate responsibility for the costs of both the capacity that they use and any capacity that is not reserved by point-to-point customers. In this regard, native load and third-party network customers face a payment risk that point-to-point customers generally do not face. For these reasons, we do not believe that it is appropriate to require native load and network customers to assume any additional cost responsibility for the capacity that is reserved for their future use.

In response to CCEM's concerns, we recognize that offering load-based network service and reservation-based point-to-point service in one tariff may have disadvantages in that it may result in less than optimal use of the system if a utility overestimates its load. However, by requiring that available capacity reserved for native load be posted on OASIS and be available to others except when actually needed to serve native load, we believe Order No. 888 substantially relieves the incentive to over-reserve for native load and goes a long way toward assuring full and efficient use of the system.

With regard to the concern raised by VA Com, the transmission provider has an ongoing duty to plan and construct its system in a prudent manner in order to meet all of its firm service obligations. We also reiterate that

> public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon.[141]

There is a risk of under-or over-projecting the transmission needs of native load and network customers, and the native load and network customers' cost responsibilities reflect this additional risk. In response to VA Com's request, we note that nothing in our regulations prohibits a state commission from overseeing a utility's retail native load growth projections. Finally, concerns regarding the accuracy of load growth projections for native load and network customers may be raised when a transmission service agreement is filed with the Commission or in a separate section 206 proceeding.

6. Capacity Reassignment

In the Final Rule, the Commission concluded that a public utility's tariff must explicitly permit the voluntary reassignment of all or part of a holder's firm transmission capacity rights to any eligible customer.[142]

(1) Reassignable Transmission Services

The Commission concluded that point-to-point transmission service should be reassignable, but that network transmission service is not reassignable.[143]

(2) Terms and Conditions of Reassignments

a. General

In effecting a reassignment, the Commission found that the assignor may deal directly with an assignee without involvement of the transmission provider.[144] Alternatively, the Commission explained that the assignor may request the transmission provider to effect a reassignment on its behalf, in which case the transmission provider must post the available capacity on its OASIS and assure that any revenues associated with the reassignment are credited to the assignor. The Commission further found that, among other things, any assignment must be posted on the transmission provider's OASIS within a reasonable time after its effective date.

[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.

b. Contractual Obligations

The Commission concluded that while assignors and assignees may contract directly with each other, the assignor will remain obligated to the transmission provider and the assignee will be liable solely to the assignor.[145] The Commission, however, did permit mutually agreeable alternatives to this approach.

c. Price Cap

The Commission concluded that the rate for any capacity reassignment must be capped by the highest of: (1) the original transmission rate charged to the purchaser (assignor), (2) the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment, or (3) the assignor's own opportunity costs capped at the cost of expansion (Price Cap).[146]

Rehearing Requests

Scheduling Transmission Service by Assignees

CCEM requests that the Commission clarify that an assignee of transmission capacity, or its agent, is permitted to schedule transmission service directly with the transmission provider.

Network Transmission Service

American Forest & Paper declares that the Commission erred in finding that network service is not reassignable. American Forest & Paper argues that there is no technical reason for the Commission's position. According to American Forest & Paper, the Commission merely perpetuates the myth that in point-to-point transmission the contract actually determines the path of the flow of electrons. In fact, American Forest & Paper argues, the only issue is arriving at a nondiscriminatory and equitable price.

VT DPS argues that there is no reason network capacity rights cannot be defined during the period of a reassignment as VT DPS suggested in its comments:

> Section 2.6 of the NorAm NIS Rate Schedule (Appendix B to the Initial NOPR comments of VDPS) is a provision which allows the reassignment of network service. Reassignment under the NorAm tariff would work this way: During the period of the assignment, both the original and replacement customers' network service entitlements are defined as specified contract quantities, the sum of which is equal to the original customer's highest coincident peak load during the 12 months preceding the

[145] FERC Stats. & Regs. at 31,697; *mimeo* at 180–81.

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

assignment. During the period of the assignment, that contract quantity, not the actual use of the system by the original and replacement shipper, will be used to determine the two customers' load ratio share responsibility. The original and replacement customers are free to divide responsibility for interim contract demand between them as they see fit.[147]

PA Coops argue that the Commission failed to explain why network customers have no capacity rights and points to a statement in Order No. 888 that network customers ''should not lose their rights to firm capacity'' as being inconsistent with the Commission's conclusion with respect to the reassignment of network service.

AMP-Ohio asserts that absent an ongoing pass-through to network customers of the revenue credits associated with sales of point-to-point service, the Commission should permit the reassignment of unused transmission capacity by network customers.

TDU Systems argue that the Commission should permit the assignment of a network customer's right to network transmission service for certain specific purposes. In particular, TDU Systems state that the Commission should permit assignment to allow a customer to coordinate, jointly operate, or pool its system with the systems of other local and regional network customers. TDU Systems argue that this provides an opportunity to maximize efficiencies without presenting the complication that the Commission has perceived with respect to the reassignment of point-to-point transmission capacity.

Price Cap

EEI asserts that the Commission's price cap creates several problems: (1) non-comparable treatment because transmission providers must credit revenues, but resellers can keep the revenues; (2) allowing sale at a price higher than paid could encourage speculation and hoarding; and (3) the transmitting utility's maximum stated rate should not include the utility's opportunity costs.

CCEM argues that transmission customers that are not transmission providers or affiliates of transmission providers should be freed from the price cap. CCEM claims that in a secondary market at market-based prices, opportunity costs can be communicated and lost opportunity costs averted.

NRECA believes that the price cap provision that permits an assignor to assign capacity at its own opportunity costs (capped at the cost of expansion) may provide firm point-to-point customers a strong economic incentive to buy up substantial firm capacity for speculative purposes and argues that this provision should be eliminated. NRECA also argues that this provision presents difficult rate substantiation questions when the assignor is not a public utility. Further, NRECA and SoCal Edison note that section 23.1 of the tariff does not include the cap at the cost of expansion.

Calculation of Assignor's Opportunity Costs

SoCal Edison asserts that the Commission must indicate how an assignor should calculate its own opportunity costs with respect to determining the price cap and should indicate that an assignor must abide by the same standard for recovering opportunity costs as the transmission provider. Carolina P&L also asserts that assignors must be held to the same standard as transmission providers when calculating opportunity costs. Carolina P&L further explains that if the opportunity costs are based on the cost of foregone transactions, the assignor should be required to post the price on OASIS.

Carolina P&L also asks that the Commission clarify how an assignor is to calculate its own opportunity costs. In particular, Carolina P&L asks if an assignor is limited to recovering the opportunity costs to which it is subject under the transmission provider's tariff or can the assignor forfeit the transaction underlying the transmission service and call the resulting difference an opportunity cost?

Resellers Into the Secondary Market

CCEM argues that the Commission should free resellers, ''who but-for the resell would not be public utilities,'' from regulation as public utilities or should minimize the regulatory burden on them.[148] It further asserts that resellers that are not transmission providers should be treated like unaffiliated power marketers and granted waivers from public utility regulations.

Participation in the Secondary Market

CCEM argues that those customers that are permitted to continue to take service under existing agreements ''should be excluded from participating in the secondary market until such time as they agree to comply with the pro forma tariff.'' (CCEM (889 rehearing request) at 7).

Commission Conclusion

Scheduling Transmission Service by Assignee

The pro forma tariff does not prohibit the assignee of transmission capacity from scheduling transmission service with the transmission provider. In fact, the tariff provides that ''the Assignee will be subject to all terms and conditions of this Tariff'' (tariff section 23.1), which would include the scheduling provision of tariff sections 13.8 and 14.6.

Network Transmission Service

We reaffirm our conclusion that network transmission service is not reassignable in the secondary market.[149] Parties have raised no new arguments that would persuade us otherwise. PA Coops are nevertheless correct in noting that network customers do have rights to firm capacity. However, a network customer's rights (as well as the transmission provider's planning responsibilities) are defined only in terms of the capacity needed to integrate the network customer's designated resources and its designated loads. These are usage- or load-based rights that are not fixed; they vary as the customer's load varies. Thus, the network customer's capacity rights are not well enough defined to be generally reassignable in the secondary market.[150]

VT DPS proposes a formula for defining a network customer's entitlement that would be operative during the period of an assignment. However, the proposed definition is simply an artifice derived from the load ratio share calculation. The formula does not result in a reassignable capacity right.

AMP–Ohio's suggestion regarding the proper treatment of the revenue credits associated with point-to-point service raises a rate issue that should be addressed in a ratemaking proceeding. However, we note that the proper treatment of such credits does not turn on the assignability of network service.

Finally, TDU Systems' recommendation that network service be reassignable only for pooling and coordination purposes is without merit. If customers wish to avail themselves of network service in order to realize

[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.

[150] 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.

benefits associated with joint or coordinated operations with other systems, they can jointly request network service from the transmission provider. To allow customers to opt into and out of network service arrangements under the guise of capacity reassignment would be an abuse of the terms and conditions of the service, which, among other things, requires the transmission provider to plan for the long-term needs of network customers.

Price Cap

We will also reaffirm our conclusions regarding the price cap applicable to capacity reassignment. We continue to believe that customers must be given limited pricing flexibility in order to achieve the full efficiency and risk management benefits of capacity reassignment.

Contrary to the assertions of EEI and NRECA, we are not persuaded that allowing the customer to reassign capacity at a rate higher than it paid, as a result of charging its own opportunity costs, will lead to speculation and hoarding. As a condition of the open access tariff, the Commission will require customers reassigning transmission capacity to fully develop their method for calculating opportunity costs and provide all information necessary to their customers in order to verify such costs. Further, we reiterate that the potential for hoarding can be mitigated by (1) allowing the transmission provider to sell any reserved but unscheduled point-to-point transmission capacity on a non-firm basis, and (2) having a price cap, which allows the reseller to charge no more than a cost-based rate, including its own opportunity cost for reassigned capacity. Therefore, the reseller will find that reassigning transmission capacity to others with higher valued uses will be in its economic self interest. In addition, any hoarding of capacity that has anticompetitive effects can be addressed under section 206.

We deny CCEM's request to remove the price cap for transmission customers that are not transmission providers or affiliates of transmission providers. As we stated in the Final Rule, we are unable to conclude that competition in the market for reassigned transmission capacity is sufficient to prevent assignors from exerting market power. Thus, we believe the opportunity cost cap should be retained.[151]

Finally, in response to EEI's request, we clarify that ''the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment'' does not include the transmission provider's opportunity costs.[152] Also, as suggested by NRECA and others, section 23.1 of the pro forma tariff will be revised to indicate that the assignor's opportunity costs are capped at the transmission provider's cost of expansion.

Calculation of Assignor's Opportunity Costs

In response to the requests of SoCal Edison and Carolina P&L, we clarify that the assignor's opportunity costs should be measured in a manner that is analogous to that used to measure the transmission provider's opportunity costs. That is, an assignor's opportunity costs include: (1) increased costs associated with changes in power purchases or in the dispatch of generating units necessary to accommodate a reassignment, and (2) decreased revenues that arise from the assignor having to reduce sales of power in order to effect the reassignment.[153]

Regarding the calculation of opportunity costs, we intend to hold assignors to the same general standard as transmission providers. Thus, consistent with our treatment of transmission providers, we will not require assignors to post their opportunity costs on the OASIS or to make the costs routinely available to the public. We will, however, require assignors to describe to their assignees their derivation of opportunity costs in sufficient detail to satisfy the assignees that the price charged does 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, as set forth in section 23.1 of the tariff.

Resellers Into the Secondary Market

The issues raised by CCEM with respect to the regulation of resellers into the secondary market are fact specific and, accordingly, we will address such issues on a case-by-case basis.

Participation in the Secondary Market

We reject CCEM's argument that those customers that are permitted by Order No. 888 to continue to take service under existing agreements should be denied access to the secondary market until they agree to comply with the pro forma tariff. CCEM's approach would undermine our determination not to generically abrogate existing agreements, and would slow the growth of the secondary market by limiting the number of eligible participants.

7. Information Provided to Transmission Customers

In the Final Rule, the Commission concluded that all necessary transmission information, as detailed in the OASIS Final Rule, must be posted on an OASIS.[154]

Rehearing Requests

No requests for rehearing addressed this matter.

8. Consequences of Functional Unbundling

a. Distribution Function

In the Final Rule, the Commission concluded that the additional step of functionally unbundling the distribution function from the transmission function is not necessary at this time to ensure non-discriminatory open access transmission.[155]

Rehearing Requests

No requests for rehearing addressed this matter.

b. Retail Transmission Service

In the Final Rule, the Commission explained that although the unbundling of retail transmission and generation, as well as wholesale transmission and generation, would be helpful in achieving comparability, it did not believe it was necessary.[156] The Commission further explained that the matter raises numerous difficult jurisdictional issues that are more appropriately considered when the Commission reviews unbundled retail transmission tariffs that may come before the Commission in the context of a state retail wheeling program.

Rehearing Requests

CCEM argues that all transmission must be unbundled, including currently bundled retail transmission service, because failure to do so is inconsistent with the Commission's assertion of jurisdiction over the rates, terms, and conditions of unbundled interstate transmission to retail customers and

[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.

authority to address retail stranded costs through its jurisdiction over such costs. CCEM notes that the Commission found it necessary in Order No. 636 to unbundle the pipeline's direct retail sales to achieve comparability (CCEM cites *FPC* v. *Conway Corp.,* 426 U.S. 271, 273 (1976) and *Mississippi River Transmission Corp.* v. *FERC*, 969 F.2d 1215 (D.C. Cir. 1992) for the proposition that the Commission has jurisdiction over all interstate transmission).

NY Municipal Utilities and American Forest & Paper also argue that the Commission erred in not requiring the unbundling of the transmission component of *retail* sales. American Forest & Paper believes that such unbundling will facilitate competition by making the generation price transparent to all participants.

Commission Conclusion

We disagree with those entities that argue that the Commission erred in not requiring the unbundling of all transmission service, including the unbundling of transmission from retail service. As we explained in the Final Rule:

> when transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail. Under the FPA, the Commission's jurisdiction over sales of electric energy extends only to wholesale sales. However, when a retail transaction is broken into two products that are sold separately (perhaps by two different suppliers: an electric energy supplier and a transmission supplier), we believe the jurisdictional lines change. In this situation, the state clearly retains jurisdiction over the sale of the power. However, the unbundled transmission service involves *only* the provision of ''transmission in interstate commerce'' which, under the FPA, is exclusively within the jurisdiction of the Commission. Therefore, when a bundled retail sale is unbundled and becomes separate transmission and power sales transactions, the resulting transmission transaction falls within the Federal sphere of regulation.[157]

Nor is our decision not to unbundle transmission from retail generation service inconsistent with our assertion of jurisdiction over unbundled interstate transmission to retail customers. As we explained in the Final Rule and described further above, we have exclusive jurisdiction under the FPA over ''transmission in interstate commerce'' by public utilities, which includes the unbundled interstate transmission component of a previously bundled retail transaction.[158] Our assertion of jurisdiction in such a situation arises only if the retail transmission in interstate commerce by a public utility occurs voluntarily or as a result of a state retail program.

c. Transmission Provider

1. Taking Service Under the Tariff

In the Final Rule, the Commission concluded that public utilities must take all transmission services for wholesale sales under new requirements contracts and new coordination contracts under the same tariff used by others (eligible customers).[159] For sales and purchases under existing bilateral economy energy coordination agreements, the Commission gave an extension until December 31, 1996 for public utilities to take transmission service under the same tariff used by others. The Commission also gave an extension of time to December 31, 1996 for certain existing power pooling and other multi-lateral coordination agreements to comply with this requirement.[160]

Rehearing Requests

This issue is discussed above in Section IV.C.1.b.

2. Accounting Treatment

In the Final Rule, the Commission directed utilities to account for all uses of the transmission system and to demonstrate that all customers (including the transmission provider's native load) bear the cost responsibility associated with their respective uses.[161]

Rehearing Requests

No requests for rehearing addressed this matter.

D. Ancillary Services

In the Final Rule, the Commission concluded that the following six ancillary services must be included in an open access transmission tariff: (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve—Spinning Reserve Service; and (6) Operating Reserve—Supplemental Reserve Service.[162] The Commission adopted NERC's recommendations for ancillary service definitions and descriptions with modifications.[163]

The Commission determined that the transmission provider must provide and the transmission customer must purchase from the transmission provider the first two services, subject to conditions set out in the Rule. The transmission provider must offer the remaining four services to the transmission customer serving load in the transmission provider's control area. The transmission customer that is serving load in the transmission provider's control area must acquire these four services from the transmission provider or a third party, or self provide.

1. Specific Ancillary Services

a. Scheduling, System Control and Dispatch Service

In the Final Rule, the Commission concluded that Scheduling, System Control and Dispatch Service is necessary to the provision of basic transmission service within every control area.[164] The Commission further stated that this service can be provided only by the operator of the control area in which the transmission facilities used are located.

Rehearing Requests

Wisconsin Municipals asks that the Commission eliminate Schedule 1 (Scheduling, System Control and Dispatch Service) as an ancillary service and require transmission providers to include these costs in the transmission revenue requirement so the transmission provider cannot recover these costs twice. Alternatively, Wisconsin Municipals asks that, if customers do their own scheduling through an electronic data link, the charge for scheduling and dispatch be waived.

Commission Conclusion

We disagree with Wisconsin Municipals that we should eliminate this ancillary service and include its

[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).

[160] 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.

[163] 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.

costs with the transmission revenue requirement. Scheduling requires action by both the customer who provides information about a transaction and the control area that evaluates and accepts (schedules) the transaction. If a transmission provider allows a transmission customer to supply its schedules through an electronic data link, it is merely offering an alternate method of providing the transaction information required. The control area must still decide whether it can schedule a transaction. Further, scheduling a transaction is only one aspect of Scheduling, System Control and Dispatch Service. A control area must also dispatch generating resources to maintain generation/load balance and maintain security during the transaction. Only the control area operator can perform these functions. A transmission provider must unbundle the cost of these functions, including scheduling, from its base transmission rate. This requirement to unbundle ancillary services costs from the base transmission rate ensures that double recovery of scheduling costs will not occur.

b. Reactive Supply and Voltage Control From Generation Sources Service

In the Final Rule, the Commission concluded that Reactive Supply and Voltage Control from Generation Sources Service is necessary to the provision of basic transmission service within every control area.[165] Although a customer is required to take this ancillary service from the transmission provider or control area operator, the Commission stated that a customer may reduce the charge for this service to the extent it can reduce its requirement for reactive power supply.

Rehearing Requests

NRECA and TDU Systems ask that Schedule 2 of the tariff, Reactive Supply and Voltage Control from Generation Sources Service, be modified to reflect that generation facilities outside a control area can provide reactive power. They argue that parties other than the transmission provider and the transmission customer are able to supply reactive power. Similarly, Santa Clara and Redding ask the Commission to revise Schedule 2 to require the transmission provider to offer this service, but to allow the transmission customer to arrange for this service through a purchase from the transmission provider, self-provision, or purchases from third parties.[166] Blue Ridge also argues that the Commission should permit self-supply or other local supply when it is feasible and economic to do so.

APPA, Santa Clara, Redding and Cajun point out an inconsistency between Schedule 2 and the preamble. They assert that Schedule 2 of the tariff should be revised to reflect the preamble language that allows a transmission customer to supply at least a portion of its reactive power service. California DWR says that it is capable of providing Reactive Supply and Voltage Control from Generation Sources Service and that mandating that it purchase this ancillary service makes no sense. California DWR asks the Commission to clarify that it is not required to purchase this ancillary service.

TAPS asks the Commission to make clear that (1) customer-owned generation facilities that are available to supply reactive power to the transmission provider's transmission system receive a credit, (2) the extent of customer-supplied reactive power may be sufficient to eliminate the need for a separate reactive power charge paid to the transmission provider, and (3) customer-owned generation outside the control area may be eligible for a credit if it is located nearby where it can provide reactive support for the transmission provider's transmission system.[167] TAPS further asserts that reactive supply service should be viewed not on a transaction basis but on a gridwide or regionwide basis. Under this approach, according to TAPS, payments would be based on whether the user supplies more than it uses or uses more than it supplies.

Commission Conclusion

Control area operators use sources of reactive support to control voltage and maintain a stable power supply system. Because of the limited ability to transmit reactive power, these facilities must be available at or near the point of need. Therefore, reactive power support, and hence the facilities able to provide (or absorb) reactive power, must be distributed throughout the transmission system for the reliable operation of the power system. Over- or under-supply of reactive power at other points in the network do not contribute to a stable system and could harm the reliability of the system.

Although we agree with NRECA and TDU Systems that generation resources just outside the boundaries of a control area may provide some reactive support within the control area, the control area operator must be able to control the dispatch of reactive power from these generating resources. Accordingly, we will modify Schedule 2 to refer to generating facilities that are under the control of the control area operator instead of in the control area. The transmission customer's service agreement should specify the generating resources made available by the transmission customer that provide reactive support.

As noted in the Final Rule, a transmission customer can reduce (but not eliminate completely) the reactive supply and voltage control needs and costs that its transaction imposes on the transmission provider's system. For example, a customer who controls generating units equipped with automatic voltage control equipment may be able to use those units to help control the voltage locally and reduce the reactive power requirement of the transaction.[168] However, if these units are not always available or are not subject to the direction of the control area operator, their occasional use may not reduce the investment required by the control area operator in reactive power facilities. It merely reduces temporarily the cost of operating these facilities. Consistent with this understanding, we will modify Schedule 2 of the tariff to allow a transmission customer to supply at least part of the reactive power service it requires. We will continue to require reactive power service to be provided by and purchased from the transmission provider. However, a transmission customer may satisfy part of its obligation through self-provision or purchases from generating facilities under the control of the control area operator. The transmission customer's service agreement should specify all reactive supply arrangements.

We deny the California DWR and TAPS request that customer-owned generation facilities that are *available* to supply reactive power should automatically receive a credit. However, as the Final Rule states, a customer may reduce the charge for this service to the extent it can reduce its requirement for reactive power supply. We do not believe a transmission customer can satisfy all of its reactive requirements or allow the transmission provider to avoid

[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.

investment in reactive power related facilities. Concerning the other request of TAPS, we will not require that the supply of reactive power be on a gridwide or regionwide basis. Because reactive power must be supplied near the point of need, we are not persuaded that gridwide supply is feasible.

c. Energy Imbalance Service

In the Final Rule, the Commission concluded that Energy Imbalance Service must be offered for transmission within and into the transmission provider's control area to serve load in the area.[169] However, the Commission noted, a transmission customer can reduce or eliminate the need for energy imbalance service in several ways.

Energy Imbalance Service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area. For minor hourly differences between the scheduled and delivered energy, the transmission customer is allowed to make up the difference within 30 days (or other reasonable period generally accepted in the region) by adjusting its energy deliveries to eliminate the imbalance. A minor difference is one for which the actual energy delivery differs from the scheduled energy by less than 1.5 percent, except that any hourly difference less than one megawatt-hour is also considered minor. Thus, the Final Rule established an hourly energy deviation band of ±/1.5 percent (with a minimum of 1 MW) for energy imbalance. The transmission customer must compensate the transmission provider for an imbalance that falls outside the hourly deviation band and for accumulated minor imbalances that are not made up within 30 days.

(1) Description of Energy Imbalance

Rehearing Requests

North Jersey asserts that the definitions of Energy Imbalance Service and Backup Supply Service are conflicting and need clarification. North Jersey proposes that Energy Imbalance Service be clarified to state that a transmission provider will be required to supply power to a customer ''within the dispatch period of the transmission provider's tariff.'' It states that this assures power when a customer is unable to change its nominations to match its generation capabilities. On the other hand, North Jersey states that Backup Supply Service should be the supply of power for a period longer than the tariff dispatch period.

NIMO asserts that the Commission should recognize that there is another type of Energy Imbalance Service. If a generator is located in one control area, but transfers the power to load in another control area, there is a potential mismatch between the amount of power scheduled for delivery by the generator and the amount it actually provides to the operator of the control area where it is located.

Nebraska Public Power District (NPPD) states that allowing third parties to provide Energy Imbalance Service and Regulation and Frequency Response Service could jeopardize system reliability. It argues that the transmission provider must have the right to approve the third party provider of these services and the right to physically meter the loads located out of the transmission provider's control area or otherwise monitor these services to be assured that they are provided satisfactorily.

NCMPA argues that because of the potential for abuse, the Commission should grant an exemption from an energy imbalance charge if the source of the energy shortfall is a generating resource that has been turned over to the transmission provider's dispatching control for meeting control area requirements.

Commission Conclusion

We clarify that Energy Imbalance Service is used to supply energy for mismatches between scheduled deliveries and actual loads that may occur over an hour. We do not intend it to be used as a substitute for operating reserves when there is an outage of generation supply or transmission. The Final Rule states that if a customer uses either type of operating reserve, it must expeditiously replace the reserve with backup power to reestablish required minimum reserve levels.[170]

Order No. 888 specifies that there is no obligation on the transmission provider to provide power to the customer for a ''time longer than specified in the tariff'' for the customer's own backup supply to be made available.[171] The order also states that ''any arrangements for the supply of such service [*i.e.*, Backup Supply Service] by the transmission provider should be specified in the customer's service agreement.''[172] We revise the first statement to clarify that the transmission customer's service agreement, not the tariff, should specify any arrangements for backup service by the transmission provider, including the time within which backup power supply will be made available. The time should correspond to the time necessary to restore operating reserves that is generally accepted in the region and consistently followed by the transmission provider.

NIMO asserts that two types of energy imbalance can occur if the generator and the load are in different control areas. These are (1) a mismatch between the energy scheduled to be received in the load's control area and the actual hourly energy consumed by the load, and (2) a mismatch between energy scheduled for delivery from the generator's control area and the amount of energy actually generated in the hour. The Energy Imbalance Service in the Final Rule applies to the first case only. Although we agree that the second type of mismatch can occur, we will not designate as Energy Imbalance Service a mismatch between energy scheduled and energy generated. Energy Imbalance Service in this Rule applies only to the obligation of the transmission provider to correct the first type of energy mismatch, one caused by load variations.

In general, the amount of energy taken by load in an hour is variable and not subject to the control of either a wholesale seller or a wholesale requirements buyer. The Energy Imbalance Service that we require as our ancillary service has a bandwidth appropriate for load variations and should have a price for exceeding the bandwidth that is appropriate for excessive load variations. Although NIMO states correctly that, where two control areas are involved, there can also be a mismatch between energy scheduled and energy generated, NIMO has not explained why this mismatch should have the same bandwidth and price as our Energy Imbalance Service. Indeed, we believe it should not.

A generator should be able to deliver its scheduled hourly energy with precision. If we were to allow the generator to deviate from its schedule by 1.5 percent without penalty, as long as it returned the energy in kind at another time, this would discourage good generator operating practice. A generation supplier could intentionally generate less power when its generating cost is high and make it up when its cost is lower if the second type of mismatch is included in our Energy Imbalance Service. Instead, a generator will have an interconnection agreement with its

[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.

[172] FERC Stats. & Regs. at 31,711; *mimeo* at 223.

transmission provider or control area operator, and we expect that this agreement will specify the requirements for the generator to meet its schedule, and for any consequence for persistent failure to meet its schedule. This agreement will be tailored to the parties' specific standards and circumstances, and, although such arrangements must not be unduly preferential or discriminatory (*e.g.*, must be comparable for all wholesale sellers, including the transmission provider's own wholesale sales), we prefer not to set these standards generically for all parties.[173]

We disagree with NCMPA's argument regarding an exemption from Energy Imbalance Service when the control area operator controls the generating resource. As discussed above and in the Final Rule, energy imbalance results from a mismatch between a scheduled receipt and actual load in the control area of the transmission provider. Energy imbalance can occur if the actual load differs from the scheduled receipt regardless of who controls the generating resource.

As specified in the Final Rule, to ensure the reliability of the power system, a transmission customer is obligated to obtain Energy Imbalance Service and Regulation and Frequency Response Service for its transactions. We clarify for NPPD that the transmission customer may not decline the transmission provider's offer of these ancillary services unless it demonstrates to the transmission provider that it has acquired the services from another source. This demonstration must show that the customer's alternative arrangement for ancillary services is adequate and consistent with Good Utility Practice. The transmission customer's service agreement should specify any alternative arrangements for the provision of these (or any other) ancillary services.

(2) Energy Imbalance Bandwidth

As explained above, Schedule 4 (Energy Imbalance Service) of the tariff allows the transmission provider to charge a transmission customer serving load in its control area for taking an amount of energy in any hour that is 1.5 percent more or less than the amount of energy scheduled for that hour. In the pro forma tariff, the minimum amount of energy that can be assessed a charge in an hour is one megawatt-hour.

Rehearing Requests

Several entities argue that this energy imbalance bandwidth is too narrow and should be increased.[174] APPA asserts that the narrow bandwidth imposes obligations on the transmission customer that the transmission provider does not impose on itself.[175] TAPS argues that the 1.5 percent bandwidth ''makes no sense because it simply imposes a penalty for existence as a small utility.'' Redding states that the 1.5 percent energy imbalance bandwidth is not appropriate for transmission to a small utility that does not operate a control area. In opposing the narrow bandwidth, TDU Systems notes that metering error is typically within a range of ±2 percent. It further argues that it is impossible for smaller systems with low load factors, larger load swings, and the need to change the output quickly for a single unit to operate within the narrow bandwidth. Others assert that a too-narrow bandwidth creates a burdensome level of billings unless schedule changes are permitted more frequently than hourly.[176] They fear that meeting the 1.5 percent bandwidth would require expensive dynamic scheduling.

Some entities recommend a particular alternative bandwidth.[177] TDU Systems suggests a sliding scale as follows. There would be a bandwidth of ±5 percent of scheduled energy for transactions of 500 MW or less, decreasing to ±1.5 percent for transactions of 5,000 MW or more, with a minimum bandwidth of ±5 MWh in all cases. Alternatively, TDU Systems says that network customers could be entitled to a bandwidth equal to their load ratio share of the amount (not percentage) of their transmission provider's inadvertent interchange, again subject to a minimum of 5 MWh. TAPS recommends that the deviation bandwidth be changed to 6 percent of the transmission customer's daily peak demand, with a minimum bandwidth of 4 MWh.

NRECA proposes an alternative approach (previously set forth in its comments on the proposed rule): a customer's ''energy compensation balance'' should be determined for each hour based on the net energy deviation from the ''bandwidth base,'' which NRECA defines as the greater of (i) the customer's total on-line and available generator capacity associated with the generation dispatched, or (ii) the sum of a customer's maximum hourly demands at each of its recipient interfaces. NRECA states that its proposal sets forth separate compensation based on whether there is an overdelivery or an underdelivery outside a five percent bandwidth.

Wabash argues that the Commission should use a deviation bandwidth based on a period other than a single hour; for example, use a known historical number, such as the maximum hourly load during the previous calendar year. Wabash states that if a larger bandwidth is not adopted, the Commission should permit a transmission customer that is purchasing spinning or supplemental operating reserves as an ancillary service to use those purchases as the basis for an expanded deviation bandwidth. In addition, Wabash asks the Commission to clarify that an imbalance resulting from a system emergency situation caused by loss or failure of facilities should be counted as ''inadvertent loads'' and repaid in like hours at mutually agreed times and pay-back amounts.

Redding points out that the NERC (A2 Criterion) establishes a constant bandwidth for every hour of the year and should be used instead. For energy imbalances of less than 1.5 percent, Schedule 4 of the tariff allows the energy to be returned in kind within 30 days, after which payment must be made. Redding argues that the 30-day period should be deleted. Instead the Commission should follow current industry practice of allowing reasonable deviations to be carried forward into the next month so as to avoid an accounting nightmare. Finally, Redding argues that the bandwidth for network service should apply to the entire network load and not to a ''scheduled transaction.''

Wisconsin Municipals asks the Commission to clarify that if parties have reached a settlement that establishes a wider band, the transmission provider may not use Order No. 888 to avoid this settlement obligation.

TAPS argues that any charges for exceeding the bandwidth should be cost-based and compensation should be symmetrical for over-and under-deliveries.[178] TAPS further argues that

[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.

[175] *See also* TDU Systems.

[176] *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

Continued

the bandwidth should not be applied by transaction, and customers should not have to pay for imbalances caused by transmission provider dispatch mistakes.

TDU Systems states that public utilities should be placed on notice that they will not be permitted to collect 100 mills per kWh for energy supplied by a customer in excess of its schedules, as some have sought in tariffs already filed.

Commission Conclusion

Energy Imbalance Service includes a bandwidth to promote good scheduling practices by transmission customers. It is important that the implementation of each scheduled transaction not overly burden others.

We do not agree with APPA that the bandwidth imposes an obligation on the transmission customer that the transmission provider does not impose on itself. The Final Rule treats all wholesale customers comparably. The transmission provider must also use its pro forma tariff and apply the same bandwidth for sales to its wholesale customers.

Many commenters assert that the energy imbalance bandwidth of ±1.5 percent is too narrow and is difficult to meet for small utilities. Several propose an alternative bandwidth or a larger minimum deviation. We believe that the bandwidth included in the Final Rule pro forma tariff is consistent with what the industry has been using as a standard and is as close to an industry standard as anyone can set at this time. However, we will set a larger minimum deviation to meet the needs of small customers. The minimum energy imbalance is now two megawatt-hours per hour (2 MW minimum in the pro forma tariff). This adequately addresses the concerns raised by small utilities because they may exceed the bandwidth without exceeding this minimum. For example, a transmission customer that transfers less than 133 MW (1.5 percent of 133 MW is 2 MW, the minimum energy imbalance) has a larger percentage bandwidth than ±1.5 percent. The bandwidth set forth in the pro forma tariff provides a needed incentive for a transmission customer to deliver an amount of energy each hour that is reasonably close to the amount scheduled, while at the same time recognizing the needs of small utilities. To help customers with the difficulty of forecasting loads far in advance of the hour, the Final Rule pro forma tariff permits schedule changes up to twenty minutes before the hour at no charge. By updating its schedule before the hour begins, a transmission customer should be able to reduce or avoid energy imbalance and associated charges. However, we will allow the transmitting utility and the customer to negotiate and file another bandwidth more flexible to the customer, subject to a requirement that the same bandwidth be made available on a not unduly discriminatory basis.

We disagree with Wabash's request to require a transmission provider to expand its energy imbalance bandwidth for a transmission customer purchasing spinning and supplemental reserves. Unlike Energy Imbalance Service, which treats deviations between scheduled and actual hourly energy deliveries, spinning and supplemental reserves provide generating capacity that responds to contingency situations (*e.g.*, loss or failure of facilities). Order No. 888 requires a transmission customer to obtain these operating reserve ancillary services for its transactions. Therefore, Wabash is simply requesting a larger energy imbalance bandwidth. We have selected the bandwidth to promote good scheduling practices by transmission customers. A larger bandwidth may introduce poor operating practices that could affect the reliability of the system. If the Energy Imbalance Service bandwidth were larger, energy supplied within this expanded bandwidth could be provided from reserve capacity. Some reserve capacity may not then be available when needed for system reliability. However, as stated in the Final Rule, we will allow a transmission provider to assemble packages of ancillary services (not bundled with basic transmission service) that can be offered at rates that are less than the total of individual charges for the services if purchased separately.[179]

In response to Wabash's other concern, we believe that emergency situations caused by loss or failure of facilities should be addressed in the transmission customer's service agreement (or the generation supplier's separate interconnection agreement) and not as part of Energy Imbalance Service.

In response to Redding's statement that the NERC (A2 criterion) establishes a constant bandwidth for imbalances, we note that NERC has set a standard for a kind of deviation that is different from our Energy Imbalance Service. NERC's bandwidth is for inadvertent interchange between a control area and all other control areas. Redding has presented no reason that our Energy Imbalance Service bandwidth should be the same as NERC's inadvertent interchange bandwidth. Regarding its concern about the in-kind repayment period, we note that Schedule 4 does not always require a 30-day period for in-kind repayment of energy imbalances; it also permits a term that the transmission provider consistently follows and is generally accepted in the region. In addition, we clarify that the bandwidth for network service applies to the entire network load.

With respect to Wisconsin Municipals' request, we clarify that the Final Rule does not require parties to a contract that went into effect prior to July 9, 1996 to stop using a wider bandwidth established by settlement. However, service provided pursuant to a settlement that was expressly approved subject to the outcome of Order No. 888 on non-rate terms and conditions must be revised in the subsequent compliance filing to reflect the language contained in the pro forma tariff.[180] Subsequent to the compliance tariff filing, public utilities are free to file under section 205 to revise the tariffs (*e.g.*, to reflect various settlement provisions) and customers are free to pursue changes under section 206.[181]

In response to arguments regarding the price of Energy Imbalance Service, we note that the Final Rule intentionally does not provide detailed pricing requirements. We require the transmission provider to determine and apply to the Commission for appropriate rates for Energy Imbalance Service as part of its transmission tariff. Transmission customers may address any disagreements with a specific charge in the company's transmission rate case.

2. Ancillary Services Obligations

In the Final Rule, the Commission distinguished two groups or categories of ancillary services: (1) services that the transmission provider is required to provide to all of its basic transmission customers under the tariff, and (2) services that the transmission provider is required to offer to provide only to transmission customers serving load in the provider's control area. The Commission required a transmission provider that operates a control area to provide the first group of ancillary services and the transmission customer

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.

[181] FERC Stats. & Regs. at 31,770 n.514; *mimeo* at 399 n.514.

to purchase these services from the transmission provider. The Commission required a transmission provider to offer to provide the ancillary services in the second group to transmission customers serving load in the transmission provider's control area. The Commission required the transmission customer serving load in the transmission provider's area to acquire these services, but allowed the transmission customer to do so from the transmission provider, a third party or self-supply.

If the transmission provider is a public utility providing basic transmission service, but is not a control area operator, the Commission allowed the transmission provider to fulfill its obligation to provide, or offer to provide, ancillary services by acting as the customer's agent. In this case, if the control area operator is a public utility, the Commission required the control area operator to offer to provide all ancillary services to any transmission customer that takes transmission service over facilities in its control area whether or not the control area operator owns or controls the facilities used to provide the basic transmission service.

a. Obligation of a Control Area Utility

Rehearing Requests

Carolina P&L asks the Commission to clarify that the transmission provider is not required to provide control area services to another utility operating a control area that simply chooses not to provide for its own control area obligations. It argues that this is not justified in a competitive bulk power market.

Maine Public Service asserts that a transmission provider that is not a NERC-recognized control area can provide ancillary services from its own facilities. It asks that the Commission clarify that this is permissible. At a minimum, Maine Public Service states that the Commission must allow transmission providers on a case-by-case basis to establish that they provide ancillary services even if they are not NERC-recognized control areas or do not satisfy the Commission's definition (citing the initial decision in Maine Public Service Company, 74 FERC ¶ 63,011 (1996)).

Similarly, California DWR states that it has been operating since 1983 as a quasi-control area, self-providing most, if not all, of the ancillary services it uses. It also notes that it provides such services to its utility transmission providers. California DWR argues that it is entitled to appropriate compensation for all ancillary services that it provides to its transmission providers or other parties.

Commission Conclusion

In response to Carolina P&L, we clarify that the Final Rule does not require a control area operator to provide control area services within another control area.

Except for the ancillary service called Scheduling, System Control and Dispatch,[182] the Final Rule does not preclude a transmission provider that is not a control area operator from offering ancillary services to its transmission customers.

Order No. 888 requires that a transmission customer obtain or provide ancillary services for its transactions. If a transmission customer can self-supply a portion of its requirement for ancillary services (other than Scheduling, System Control, and Dispatch Service), it should pay a reduced charge for these services. As with the transmission provider, a third party may offer ancillary services voluntarily to other customers if technology permits. However, simply supplying some duplicative ancillary services (*e.g.*, providing reactive power at low load periods or providing it at a location where it is not needed) in ways that do not reduce the ancillary services costs of the transmission provider or that are not coordinated with the control area operator does not qualify for a reduced charge. The transmission customer must make separate arrangements with the transmission provider or control area operator to supply its own ancillary services and specify such arrangements in its service agreement.

b. Obligation to Provide Dynamic Scheduling

Dynamic scheduling electronically moves a generation resource or load from the control area in which it is physically located to a new control area. In the Final Rule, the Commission concluded that it would not require the transmission provider to offer Dynamic Scheduling Service to a transmission customer, although a transmission provider may do so voluntarily. If the customer wants to purchase this service from a third party, the Commission stated that the transmission provider should make a good faith effort to accommodate the necessary arrangements between the customer and the third party for metering and communication facilities.

[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.

Rehearing Requests

AMP-Ohio asks that the Commission clarify that the transmission provider is required to provide dynamic scheduling ''to the extent a transmission customer needs and is willing to pay for reasonably priced dynamic scheduling in order to support its operations, including in order to integrate its loads and resources located in more than one control area.'' Wisconsin Municipals also asks the Commission to clarify that dynamic scheduling must be provided if technically feasible and permitted by regional reliability practices.

Wisconsin Municipals further asks that the Commission clarify that if the transmission provider has agreed to provide dynamic scheduling in a settlement, it may not use its Order No. 888 implementation filing to void this obligation.

EEI asks that the Commission clarify the residual obligations of a control area utility to an entity that electronically leaves the control area via dynamic scheduling.

Commission Conclusion

In response to Amp-Ohio and Wisconsin Municipals, we note that dynamic scheduling is not a required ancillary service in Order No. 888, and we do not require a transmission provider to offer this service. However, nothing in the Final Rule precludes a transmission provider from offering it as a separate service. Furthermore, offering dynamic scheduling to integrate loads and resources in more than one control area is also not required.

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

We clarify for EEI that, once dynamic scheduling is arranged, each of the two control areas has ancillary service responsibilities under the Rule. The reactive power obligations of the original control area remain and cannot be completely supplied by distant sources. Order No. 888 requires, in the case of dynamic scheduling, both control areas to provide the first two ancillary services in their respective control areas, that is, (1) Scheduling, System Control, and Dispatch Service and (2) Reactive Supply and Voltage Control from Generation Sources Service, and the new control area to offer the remaining ancillary services to the dynamically scheduled entity. In addition, the actual energy transfers between the two control areas will require basic transmission service. We expect that any additional obligations of a control area operator to an entity that electronically leaves the control area via dynamic scheduling, such as backup procedures for the failure of telemetering equipment, will be set out in the transmission customer's service agreement.

c. Obligation As Agent

Rehearing Requests

A transmission provider must act as an agent to help the customer acquire ancillary services if the transmission provider cannot provide them itself. NRECA asks whether a non-public utility may collect a reasonable fee for its agency services in fulfilling its reciprocity requirement.

Commission Conclusion

While the Final Rule does not allow a public utility transmission provider acting as an ancillary services agent to collect a fee for its agency service, we do not have similar authority to deny a non-public utility the opportunity to charge a fee for providing an agency service. However, to the extent a non-public utility seeks to collect an agency fee from a public utility, it must meet our comparability requirements and charge a comparable fee to its own wholesale merchant function.

3. Miscellaneous Ancillary Services Issues

a. Transmission Provider as Ancillary Services Merchant

Rehearing Requests

Allegheny asserts that the sale of power in connection with ancillary services would make the transmission provider a wholesale merchant under the Commission's standards of conduct (citing section 37.3 of the Commission's Regulations). Allegheny asks that the Commission clarify that a transmission provider's employee responsible for providing ancillary services is not engaged in a wholesale merchant service that would trigger the functional separation requirement.

Commission Conclusion

We clarify that the transmission provider's sale of ancillary services associated with its provision of basic transmission service is not a wholesale merchant function for purposes of Order No. 889. This is because the provision of ancillary services is essential for providing transmission service. However, the sale of ancillary services not associated with the transmission provider's provision of basic transmission service is a wholesale function for purposes of Order No. 889. Thus, if an employee is marketing an ancillary service independent of the transmission provider's obligations to provide transmission service, *i.e.,* as a third party to another transmission provider's basic transmission service customer, the employee would be providing a wholesale merchant function and the Order No. 889 Standards of Conduct apply.

b. QF Receipt of Ancillary Services

Rehearing Requests

North Jersey argues that the Commission did not engage in reasoned decisionmaking in ruling that Real Power Loss Service is not an ancillary service. It asserts that this service must be provided by the transmission provider. North Jersey further argues that, because the Commission describes the furnishing of real power loss as a sale of power, this could prevent a PURPA qualifying facility (QF) from being a transmission service customer. North Jersey states that a QF faces power purchase and resell restrictions under the Commission's regulations. North Jersey asks that the Commission find that receipt of Real Power Loss Service from a third party to complete a transmission transaction is not a purchase and resale of power. In addition, North Jersey requests that the Commission clarify that receipt of ancillary services by a QF does not constitute a purchase and resale of electric power that would jeopardize its status as a QF (clarification also requested in ER95–791–000).[183]

Commission Conclusion

The Commission disagrees with North Jersey's assertion that Real Power Loss Service should be an ancillary service that must be provided by the transmission provider. As stated in the Final Rule, it is not necessary for the transmission provider to supply Real Power Loss Service to effect a transmission service transaction. Although the transmission customer is responsible for losses associated with its transmission service, supply of losses is purely a generation service that can be (1) self supplied; (2) purchased from the transmission provider, if it offers this service; or (3) purchased from a third party.

We clarify that a QF arrangement for receipt of Real Power Loss Service or ancillary services from the transmission provider or a third party for the purpose of completing a transmission transaction is not a sale-for-resale of power by a QF transmission customer that would violate our QF rules.

c. Pricing of Ancillary Services

In the Final Rule, the Commission concluded that it would consider ancillary services rate proposals on a case-by-case basis and offered general guidance on ancillary services pricing principles.[184]

Rehearing Requests

NRECA and TDU Systems argue that there should be truth in transmission pricing so that the rate is clearly identified as including or excluding ancillary services.

AEP asserts that if a purchaser of ancillary services has alternative suppliers of these services, then either the transmission provider should not be required to provide those services or it should be able to charge market rates for them. Otherwise, according to AEP, the market is skewed in favor of the customer.

Illinois Power argues that if a transmitting utility demonstrates that it incurs incremental costs from its obligation to offer to provide the required ancillary services, it should be permitted to recover such costs through an adjustment to base transmission rates.

Commission Conclusion

The Final Rule requires unbundling of individual ancillary services from basic transmission service. We point out to NRECA and TDU Systems that the transmission provider must post and update prices for basic transmission and each ancillary service on its OASIS. As discussed below in Section IV.G.1.h. (Discounts), the Commission is revising its policy regarding the discounting of the price of transmission services. There, we establish three principal requirements for discounting basic transmission service.[185] We clarify here that these principal requirements apply to discounts for ancillary services provided by the transmission provider in support of its provision of basic transmission service. However, because ancillary services are generally not path-

[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.

specific, a discount agreed upon for an ancillary service must be offered for the same period to all eligible customers on the transmission provider's system. In addition, if a transmission provider offers any rate or packaged ancillary service discounts, it must post them on its OASIS and make them available to affiliates and non-affiliates on a basis that is not unduly discriminatory. In this manner, any discounting of ancillary service prices is visible to all market participants. We will require that, as soon as practicable, any ''negotiation'' of discounts between a transmission provider and potential transmission (and ancillary) service customers should take place on the OASIS.[186]

We continue to require a transmission provider to provide or offer to provide the six ancillary services, even if the transmission customer has some alternative suppliers. We distinguished these six services from others (*e.g.*, Real Power Loss Services) for which many suppliers are typically available. In some cases, only the transmission provider can provide the ancillary service; in other cases too few providers are available to create a market for these services. Further, we were persuaded by the comments of NERC and others that these services are essential for reliability; if a customer must obtain these services to obtain transmission service there must be a default provider of these services. However, market-based rates for some of the ancillary services may be appropriate if the seller lacks market power for such services. Market power issues regarding ancillary services have to be addressed before market-based rates for ancillary services can be approved, as requested by AEP. We will consider market-based rates for ancillary services on a case-by-case basis.

In reply to Illinois Power, we agree that the transmission provider may incur incremental costs from its obligation to offer to provide ancillary services. We believe, however, these costs should be included in the price for those services. Order No. 888 requires the transmission provider to unbundle the cost of ancillary services from the base transmission rate. A rebundling of these costs with the base transmission rate, as Illinois Power requests, would not satisfy the unbundling requirement.

E. Real-Time Information Networks

In the Final Rule, the Commission concluded that in order to remedy undue discrimination in the provision of transmission services it is necessary to have non-discriminatory access to transmission information, and that an electronic information system and standards of conduct are necessary to meet this objective.[187] Therefore, in conjunction with the Final Rule, the Commission issued a final rule adding a new Part 37 that requires the creation of a basic OASIS and standards of conduct.

Rehearing Requests

Rehearing requests raising arguments with respect to specific aspects of OASIS and standards of conduct are addressed in Order No. 889–A, issued concurrently with this order.

F. Coordination Arrangements: Power Pools, Public Utility Holding Companies, Bilateral Coordination Arrangements, and Independent System Operators

In the Final Rule, the Commission explained that its requirement for non-discriminatory transmission access and pricing by public utilities, and its specific requirement that public utilities unbundle their transmission rates and take transmission service under their own tariffs, apply to all public utilities' wholesale sales and purchases of electric energy, including coordination transactions.[188] While the Commission ''grandfathered'' certain existing requirements agreements and non-economy energy coordination agreements, it also determined that certain existing wholesale coordination arrangements and agreements must be modified to ensure that they are not unduly discriminatory. The Commission then discussed (as set forth further below) how and when various types of coordination agreements will need to be modified, and when public utility parties to coordination agreements must begin to trade power under those agreements using transmission service obtained under the same open access transmission tariff available to non-parties.

The Commission explained that it was addressing four broad categories of coordination arrangements and accompanying agreements: ''tight'' power pools, ''loose'' power pools, public utility holding company arrangements, and bilateral coordination arrangements.

In addition, the Commission explained that ISOs may prove to be an effective means for accomplishing comparable access and, accordingly, provided guidance on minimum ISO characteristics.

1. Tight Power Pools

The Commission required public utilities that are members of a tight pool to file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) an individual Final Rule pro forma tariff; or (2) a joint pool-wide Final Rule pro forma tariff.[189] However, the Commission required them to file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and to begin to take service under that tariff for all pool transactions no later than December 31, 1996.[190] The Commission also required the public utility members of tight pools to file reformed power pooling agreements no later than December 31, 1996 if the agreements contain provisions that are unduly discriminatory or preferential.

If a reformed power pooling agreement allows members to make transmission commitments or contributions in exchange for discounted transmission rates, the Commission indicated that the pool may file a transmission tariff that contains an access fee (or file a higher transmission rate) for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs.

Rehearing Requests

Consumers Power asks the Commission to clarify that Order No. 888 does not preclude the Michigan Electric Coordinated Systems (MECS) from being in compliance by removing all transmission functions from pool control and allowing pool members or the pool to take transmission service from transmission-owning pool members under their open access tariffs. It asserts that this would be an interim placeholder alternative while retail deliberations continue in Michigan. Furthermore, as one of the two members of MECS, Consumers Power indicates that it would be willing to consider further modifications that would liberalize membership criteria during the transition period if the Commission otherwise clarifies that the MECS Pool is in compliance with Order No. 888.

[186] ''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.

[190] 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.

NY Municipals request that the Commission clarify that, particularly if generation services are to be provided at market-based rates, monopoly transmission services must continue to be provided at cost-based rates (raised in connection with the NYPP). They also ask that the Commission clarify that joint pool-wide tariffs must incorporate transmission rates that are uniform (non-pancaked) and strictly based on the embedded costs of the transmission facilities and related transmission expenses. Moreover, NY Municipals argue that transmission owners should receive a credit based on the depreciated costs of their transmission facilities.

TAPS also asks the Commission to clarify that pool-wide and system-wide tariffs must contain non-pancaked rates.

Commission Conclusion

While Consumers Power's proposal to remove transmission functions from pool control, if implemented in a non-discriminatory fashion, would satisfy the comparability requirements of Order No. 888, the Commission encourages Consumers Power to pursue a pool-wide tariff.[191]

NY Municipal Utilities' concern that rates for transmission service will not be priced at cost-based rates is ill-founded. While Order No. 888 does not establish any specific pricing methodology for tariff transmission service, the Commission expects all transmission rate proposals filed on compliance to be cost based and to meet the standard for conforming proposals set out in the Commission's Transmission Pricing Policy Statement. (*See* 18 CFR 2.22).

Regarding NY Municipal Utilities' and TAPS's requests for a uniform tariff with non-pancaked rates, Order No. 888 does not require a non-pancaked rate structure unless a non-pancaked rate structure is available to pool members. Although the Commission has encouraged the industry to reform transmission pricing, the Commission's current policy does not mandate a specific transmission rate structure.

With regard to NY Municipal Utilities' concern about market-based rates for generation, public utility owners of existing NYPP generation are not eligible to charge market-based power sales rates absent Commission approval. Order No. 888 allows market-based rates only if the seller in a case-specific filing demonstrates it meets the Commission's well-established criteria of showing that it and its affiliates do not have or have adequately mitigated transmission market power and generation market power, that there are no other barriers to entry, and there is no evidence of affiliate abuse or reciprocal dealing. With regard to requests to make market-based sales from *new* generation, the seller does not have to submit evidence of generation market power in long-run bulk power markets (subject to challenge where specific evidence can be presented);[192] however, for sales from existing generation at market-based rates, the applicant must demonstrate that it lacks, or has fully mitigated, generation market power.[193]

In response to NY Municipals' request that transmission owners that contribute transmission facilities to a power pool should receive a rate credit based on the depreciated costs of those transmission facilities, we agree that this is one possible way of reflecting a pool member's contributions or commitments of transmission facilities. However, NY Municipals has provided no rationale as to why we should limit the broader approach we adopted in Order No. 888 to this single mechanism.[194]

2. Loose Pools

In the Final Rule, the Commission found that public utilities within a loose pool must file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) an individual Final Rule pro forma tariff; or (2) a pool-wide Final Rule pro forma tariff.[195] However, the Commission required that they file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and begin to take service under that tariff for all pool transactions no later than December 31, 1996.[196] The Commission also required that the public utility members of loose pools file reformed power pooling agreements no later than December 31, 1996 if the agreements contain provisions that are unduly discriminatory or preferential. They also must file a joint pool-wide tariff no later than December 31, 1996.

If a reformed pooling agreement allows members to make transmission commitments or contributions in exchange for discounted transmission rates, the Commission determined that the pool may file a transmission tariff that contains an access fee (or a higher transmission rate) for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs.

Rehearing Requests

Union Electric asserts that the definition of loose pools is so vague that many public utilities, regional organizations and multi-lateral arrangements, which are not actually pools, may incorrectly be deemed loose pools by third parties. Thus, Union Electric asks the Commission to clarify that members or parties to multi-lateral arrangements only need to offer transmission services pursuant to their own individual company tariffs.

EEI asks the Commission to clarify the nature of the tariffs that loose pools may file to comply with the Rule to ensure that the members are not required to file tariffs for services that they do not now provide. EEI also requests that, where members of loose pools currently provide transmission services to each other, they may continue to provide such services to each other under each member's individual pro forma tariff in lieu of a pool-wide tariff (provided that those services are made available to all eligible entities on a non-discriminatory basis). Similarly, Montana Power argues that members of loose pools should be allowed to meet comparability by filing individual open access tariffs, without having to file a pool-wide tariff.[197]

Public Service Co of CO asserts that the primary purpose of the Inland Power Pool is to provide for reserve sharing during emergency conditions, although the pool agreement also allows for economy transactions. It argues that another way to comply with the Rule should be to eliminate the economy energy schedule of the Inland Power Pool Agreement. Moreover, Public Service Co of CO argues that given the number of non-jurisdictional entities within the Inland Power Pool, it may be impossible to agree on a pool-wide tariff. El Paso adds that Inland Power Pool should not be treated as a loose

[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.

[192] FERC Stats. & Regs. at 31,657; *mimeo* at 64–65; section 35.27.

[193] 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.

[196] 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.

pool because it functions as a reserve sharing mechanism and not as a pool.

Utilities For Improved Transition asks the Commission to clarify that pool members or members of other entities do not have to provide more transmission services than they already provide on a voluntary basis to each other. It contends that there is no record to support a broader obligation and would cause massive disruption and the disintegration of many existing pools. Utilities For Improved Transition maintains that pools should have substantial leeway to develop arrangements reflecting their diverse memberships and the diverse contributions made.

VEPCO seeks clarification whether the Commission intended to impose the single-system tariff requirement only with respect to multilateral agreements that provide for system-wide transmission rates for the parties to the agreements.

TAPS asks the Commission to clarify that section 35.28(c)(3) includes all pools and all holding company systems, as well as any multi-lateral agreement so long as the multi-lateral agreement explicitly or implicitly addresses transmission (*e.g.,* by providing for a transaction without assessing transmission costs in connection with that transaction).

Commission Conclusion

In response to parties seeking clarification of the definition of a loose pool, the Commission clarifies that a loose pool is any multilateral arrangement, other than a tight power pool or a holding company arrangement, that explicitly or implicitly contains discounted and/or special transmission arrangements, that is, rates, terms, or conditions. The Commission requires public utilities that are members of a loose pool to either (1) reform their pooling arrangements in accordance with Order No. 888 or (2) excise *all* discounted and/or special arrangements transmission service from the pooling arrangement. That is, in the latter case the members could continue to provide other services (*e.g.,* generation), but would cease to be a loose pool for purposes of Order No. 888.

The primary goal of Order No. 888's requirements for pooling arrangements, including ''loose'' pools, is to ensure comparability regarding transmission services that are offered on a pool-wide basis. We believe comparability for loose pools can be achieved if pooling agreements are modified: (1) to allow open membership and (2) to make the transmission service in the loose pool agreement available to others. While the Commission encourages pool-wide transmission tariffs that offer the full range of transmission services included in the pro forma tariff, we will not require, under the comparability principles of Order No. 888, that pool members offer to third parties transmission services that they do not provide to themselves on a pool-wide basis. For example, if existing loose pool members do not offer network services to each other, they do not have to expand the pool services to offer network services to themselves or any third parties. Additionally, we do not find it to be unduly discriminatory to provide some pool-wide transmission services to members under a pooling agreement and to provide other transmission services to members under the individual tariff of each member, as long as members and non-members have access to the same transmission services on a comparable basis and pay the same or a comparable rate for transmission.[198]

The Commission notes that the Inland Power Pool agreement provides for non-firm transmission service (Service Schedule D) for emergency service, scheduled outage service, and economy energy service. The Inland Power Pool agreement provides members preferential transmission rates for deliveries of emergency service, *i.e.*, members will provide free non-firm transmission service at a higher priority than any other non-firm transactions. Such preferential service is not available to non-members. We consider any rates, terms or conditions of transmission service that favor members over non-members to be unduly discriminatory and preferential, whether embodied explicitly or implicitly in a loose pooling agreement. Pool members can either amend the agreement to provide comparable services to others and open the pool to new members, or amend the agreement to eliminate any preferential transmission availability and/or pricing.

In response to TAPS, the Commission agrees that Section 35.28(c)(3) applies to any pool, holding company system or multi-lateral agreement that contains explicit or implicit transmission rates, terms, or conditions.[199] For example, if a utility offers transmission without charge as part of such an agreement, it must offer transmission to all parties requesting a similar service either without charge or at an access fee or other transmission rate that comparably reflects transmission-related costs borne by members of the agreement.[200]

3. Public Utility Holding Companies

In the Final Rule, the Commission required that holding company public utility members, with the exception of the Central and South West (CSW) System, file a single system-wide Final Rule pro forma tariff permitting transmission service across the entire holding company system at a single price within 60 days of publication of the Final Rule in the Federal Register.[201]

With respect to CSW, the Commission directed the public utility subsidiaries of CSW to consult with the Texas, Arkansas, Oklahoma and Louisiana Commissions and to file not later than December 31, 1996 a system tariff that will provide comparable service to all wholesale users on the CSW System, regardless of whether they take transmission service wholly within ERCOT or the SPP, or take transmission service between the reliability councils over the North and East Interconnections.

The Commission gave public utilities that are members of holding companies an extension of the requirement to take service under the system tariff *for wholesale trades* between and among the public utility operating companies within the holding company system until December 31, 1996—the same extension it granted to power pools.[202] In addition, the Commission indicated that it may be necessary for registered holding companies to reform their holding company equalization agreement to recognize the non-discriminatory terms and conditions of transmission service required under the Final Rule pro forma tariff.

Rehearing Requests

FL Com asks the Commission to clarify whether it intends to require operating company members of a registered holding company to charge each other the same wheeling charge to be charged to others even though others pay nothing for transmission construction. FL Com argues that such

[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).

[200] *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.

a charge would be inconsistent with the Commission's traditional treatment of public utility holding companies as a single entity.

AL Com asks the Commission to clarify that ''intra-holding company transactions in support of economic dispatch across a single integrated system should not be subjected to additional transmission charges, while transactions between operating companies for the benefit of wholesale customers not included within the definition of native load customer require distinct transmission charges.'' [203]

Southern asks the Commission to clarify that transactions between public utility operating subsidiaries within a holding company system for the benefit of native load customers fall within the network service for which they are assigned cost responsibility under the Final Rule tariff.

AEP asserts that the Commission has provided no reason for requiring holding companies to use the pro forma tariff for intra-pool transactions. AEP asks the Commission to clarify whether the Rule applies to AEP. It asserts that the Preamble states that all members of holding company systems must use the pro forma tariff for intra-system transactions, but the regulatory text requires only a member of a public utility holding company ''arrangement or agreement that contains transmission rates, terms or conditions * * *.'' AEP explains that the AEP System Interconnection Agreement and Transmission Agreement do not contain transmission rates, terms or conditions and the members do not offer transmission service to one another.

However, AEP argues that, if the Rule applies to AEP, Order No. 888 contains no explanation of why or how a different intra-pool allocation of transmission costs than would result from the pro forma tariff prejudices transmission users. It asserts that (1) AEP's allocation has been subject to extensive review over the last few years, (2) AEP treats itself as a single system, not as a collection of individual members, (3) each member carries its fair share of transmission costs, and (4) compliance with the Commission's requirement would be onerous. If the Commission does not remove this requirement, AEP requests waiver of the requirement.

Similarly, Allegheny Power asserts that its Power Supply Agreement (PSA) does not provide for ''wholesale trades.'' It argues that the PSA is immaterial to all transmission services, including intra-company exchanges. Because the PSA is an existing contract that the Final Rule does not propose to abrogate, Allegheny Power asserts that the PSA need not be reformed under the Final Rule. Allegheny states that it will provide new wholesale service to itself and others under its open access tariff which was accepted for filing on December 6, 1995 in Docket No. ER96–58.

Union Electric assumes that the ''rule is intended solely to mean that a holding company system would use the network integration part of the tariff, for its intra-system 'wholesale trades.' Indeed, if Union Electric and CIPS were required to take point-to-point service for their wholesale trades, they would be placed in an inferior and non-comparable position vis-a-vis customers on the Ameren tariff who will be entitled to single-system transmission service for a single or postage-stamp charge.'' (Union Electric notes that Union Electric and CIPS are currently seeking approval to merge, with the combined facilities being operated as the Ameren System.)

NU believes that Order No. 888 could be construed to require NU System Companies to charge each other as separate entities for transmission service in connection with intra-system cost allocations as if off-system wholesale sales had occurred. NU argues, however, that this is inconsistent with Commission precedent in treating the NU System Companies as a single integrated system and would give retail native load customers service inferior to that of wholesale native load (*i.e.*, network) customers. NU further argues that it will result in duplicative transmission charges for energy flows between the NU System Companies. Moreover, NU asserts that viewing NU as a single system for establishing transmission rates, but as separate companies with respect to energy flows that result from economic dispatch of their generation to native load is inconsistent with the treatment of multistate non-holding company utilities and is thus discriminatory.

Blue Ridge seeks clarification that, to avoid double payment for transmission, ''CSW must file its compliance filing resolving comparability issues and the appropriate CSW ERCOT transmission rate prior to September 1, 1996.'' Blue Ridge asserts that CSW must resolve a potential conflict between its rate structure and the new PUCT wheeling rule by September 1, 1996 (contemplated effective date for interim PUCT transmission rates).

Commission Conclusion

In requiring holding companies to file a pool-wide tariff, the Commission does not intend that transmission service provided by the operating subsidiaries to one another on behalf of their respective native loads be subjected to additional transmission charges. The Commission recognizes that the operating subsidiaries of a holding company bear cost responsibility for transmission facilities by virtue of ownership of such facilities. In many, if not all cases, transmission costs are equalized among operating subsidiaries through transmission equalization agreements (*e.g.*, AEP's Transmission Agreement).

However, the Commission does intend, pursuant to Order No. 888, that holding company operating subsidiaries take transmission service under the same tariff rates, terms, and conditions as third-party customers that seek transmission service over the holding company system. This applies to all holding company systems that rely upon the transmission facilities of the individual operating subsidiaries to support central economic dispatch—including AEP and Allegheny. However, as suggested by Southern and Union Electric, the Commission anticipates that transmission service for an operating subsidiary's native load would be treated as network service under the pro forma tariff. Accordingly, the CP demands of each operating subsidiary's native load would establish each operating subsidiary's transmission cost responsibility related to network service over the integrated transmission facilities of the holding company system.

Thus, in response to the AL and FL Commissions, Southern, and NU, intra-holding company transactions in support of economic dispatch would not be subjected to ''additional'' transmission charges.[204] The load ratio pricing mechanism of the network portion of the tariff should ensure that each operating company bears its proportionate share of transmission costs without jeopardizing or otherwise penalizing these types of intra-system transactions. Moreover, any off-system sales would have to be taken under the point-to-point provisions of the tariff. As we noted in Order No. 888, ''it may be necessary for registered holding companies to reform their holding

[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.

company equalization agreement to recognize the non-discriminatory terms and conditions of transmission service required under the Final Rule pro forma tariff.'' [205] However, nothing in Order No. 888 mandates any change to the method chosen for apportioning transmission revenues among the operating companies, which may be based, for example, upon equalizing transmission investment responsibility.

The concerns raised here by Blue Ridge are resolved on an interim basis because the PUCT has accepted the filing of CSW's Federal tariff as adequate in the Texas proceeding until differences between the Order No. 888 rate structure and the PUCT rate structure are resolved. If, CSW implements a new ERCOT transmission tariff in response to actions of the PUCT, then affected parties may bring any remaining concerns to the Commission's attention at that time through a section 206 complaint.

We note that the issue raised here by Blue Ridge is very similar to the one raised by Tex-La and East Texas Electric Cooperative, and addressed by the Commission's recent order, in *Houston Lighting & Power Co.,* 77 FERC ¶ 61,113 at 61,439 (1996). There, the Commission found that it would be premature to address this issue at that time, and noted that parties would have an opportunity to raise their concerns after the PUCT finalizes its ERCOT tariff.

4. Bilateral Coordination Arrangements

In the Final Rule, the Commission required that any bilateral wholesale coordination agreements executed after the effective date of the Final Rule would be subject to the functional unbundling and open access requirements set forth in the Rule.[206] In addition, the Commission required that all bilateral economy energy coordination contracts executed before the effective date of the Rule be modified to require unbundling of any economy energy *transaction* occurring after December 31, 1996. Moreover, the Commission permitted all non-economy energy bilateral coordination contracts executed before the effective date of the Rule to continue in effect, but subject to section 206 complaints.

To compute the unbundled coordination compliance rate, the Commission indicated that the utility must subtract the corresponding transmission unit charge in its open access tariff from the existing coordination rate ceiling. However, the Commission noted, if a utility's transmission operator offers a discounted transmission rate to the utility's wholesale marketing department or an affiliate for the purposes of coordination transactions, the same discounted rate must be offered to others for trades with any party to the coordination agreement. In addition, the Commission explained that discounts offered to non-affiliates must be on a basis that is not unduly discriminatory.

Rehearing Requests

SoCal Edison seeks clarification as to how Order No. 888 affects package agreements (*i.e.,* bilateral contracts that provide some or all of requirements service, coordination service, or transmission service). In particular, SoCal Edison asks (1) what specific functions of each must be modified to comply with Order No. 888; (2) whether a sale of non-firm energy made pursuant to a package agreement must comply with the unbundling requirements for coordination contracts; (3) whether the requirement to remove preferential transmission access or pricing provisions applies to existing or future transmission services provided pursuant to package agreements; if so, what is the deadline; and (4) whether the rulings with respect to *Mobile-Sierra* apply to package agreements.[207]

APPA argues that the Commission should require *all* coordination arrangements to be subject to Order No. 888. CCEM asserts that to the extent non-economy energy coordination agreements are allowed to remain bundled, they should be identified in connection with determinations of available transfer capacity and, because they should only be a transitional matter, should be subject to a sunset date of December 31, 1996.

According to Utilities For Improved Transition, requiring the subtraction of the current tariff transmission rate from the current rate ceiling, without increasing the residual sales price, will force transmission providers to fail to recover their full costs of providing service because the Commission has previously prohibited these rates from including a transmission component (citing *Green Mountain,* 63 FERC ¶ 61,071 at 61,307–08 (1993) and *Cleveland Electric,* 63 FERC ¶ 61,244 at 62,277–78 (1993)).[208]

Union Electric also argues that the Commission should delete the requirement that the utility subtract the corresponding transmission unit charge in its open access tariff from the existing coordination rate ceiling. According to Union Electric, actual bilateral economy sales do not include adders for recovery of transmission costs, but are typically limited to production or generation costs. Union Electric further asserts that the definition of economy energy coordination agreement is so open-ended, it may apply to many types of coordination transactions that are not mere energy economy sales. Union Electric argues that a split-the-savings charge cannot be unbundled in the manner described by the Commission because it is an incorrect assumption that the rate ceiling for every economy energy coordination sales agreement includes a transmission cost component. If Union Electric is required to arbitrarily subtract a transmission charge for its economy sales, it argues that it will be penalized. At a minimum, it argues, a utility should be permitted to submit a list of economy coordination rate schedules that it believes to be already unbundled and should not have to subtract a transmission charge. Alternatively, it argues that the Commission should not require unbundling unless the Commission determines that the existing rate ceiling has been cost justified on a basis that includes an allowance for the full recovery of transmission function cost.[209]

Commission Conclusion

SoCal Edison represents that its package agreements include requirements services as well as coordination services. For existing bilateral economy energy coordination agreements, Order No. 888, as clarified by the Commission's May 17 Order, requires the unbundling of transmission from generation for all such contracts on or before December 31, 1996.[210] Thus, any economy energy service included in existing package agreements must be unbundled.

Regarding non-firm energy sales made under a package agreement, SoCal Edison provides no information distinguishing that service from other

[205] 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.

economy energy coordination transactions, which include all ''if, as and when available'' services (*see* section 35.28(b)(2)). Absent more information, non-firm energy sales should be unbundled.

We further note that our requirements concerning unbundling of bilateral coordination arrangements apply regardless of whether such arrangements are governed by the public interest or just and reasonable standard of review.

With respect to APPA's concerns, the Final Rule provides that all bilateral economy energy coordination contracts executed before the effective date of the Final Rule must be modified to require unbundling of any economy energy transaction occurring after December 31, 1996. Non-economy energy bilateral coordination contracts executed before the effective date of the Final Rule, however, were allowed to continue in effect, but subject to complaints filed under section 206 of the FPA.[211] We drew this distinction for both policy and practical reasons. The ability to use discounts on transmission in order to favor short-term economy energy sales made out of the transmission provider's own generation was of particular concern to the Commission. Thus, in order to eliminate the ability of transmission providers to exercise undue discrimination for short-term coordination transactions under existing umbrella-type agreements, we required unbundling by December 31, 1996.[212] However, non-economy energy coordination agreements presented a different situation.

In the Final Rule, we expressed a particular concern with not abrogating non-economy energy coordination agreements, which we indicated may reflect complementary long-term obligations among the parties.[213] Non-economy energy coordination agreements consist for the most part of long-term reliability arrangements. Providing for the abrogation of these arrangements could cause special problems for the reliable operation of the grid. Examples include agreements governing sales during emergency or maintenance periods. These agreements, unlike economy energy agreements where trade is on an ''as, if and when available'' basis, often have specified terms governing the parties' responsibilities. As a result, many non-economy energy coordination agreements are more akin to requirements contracts than to economy energy coordination agreements. Therefore, we determined to permit this category of contracts to run their course, absent a case specific complaint. The burden would be on the complainant to demonstrate that the transmission component of a non-economy energy coordination agreement is unduly discriminatory or otherwise unlawful. The Commission would decide based on the facts of the case whether unbundling is the appropriate remedy. Neither CCEM nor APPA have presented evidence or convincing arguments as to why these types of agreements should be unbundled generically.[214]

The Commission affirms the requirement in Order No. 888 that the transmission rate for any economy energy coordination service be unbundled. The Commission states in Order No. 888 that to adequately remedy undue discrimination, public utilities must remove preferential transmission access and pricing provisions from agreements governing their transactions.[215] In the cases cited by Utilities For Improved Transition, the Commission prohibited the utility from charging a split-savings rate *plus* a contribution to fixed costs. The Commission has long allowed utilities to set their coordination rates by reference to their own costs (cost-based ceilings) or by dividing the pool of benefits (fuel cost differentials) brought about by the transaction.[216] Utilities have been free to design a rate using either method but not both. Regardless of the method adopted to set a bundled rate on file (a seller's own costs or a sharing of transaction benefits), a bundled rate constitutes the *total charge* for all components and must now be unbundled.

A split-savings rate is set without reference to the seller's fixed costs and, therefore, Union Electric's argument is not germane. We are not requiring that the present rate be adjusted upward or downward. Rather, we are requiring disassembly of the existing rate into component parts one of which represents the rate being charged for transmission service. If a utility is no longer satisfied that an existing rate is compensatory, with regard to either the generation component or the transmission component, it may file an appropriate revision under section 205.

ISO Principles

In the Final Rule, the Commission set out certain principles that will be used in assessing ISO proposals that may be submitted to the Commission in the future.[217] The Commission emphasized that these principles are applicable only to ISOs that would be control area operators, including any ISO established in the restructuring of power pools.

The Commission set forth the following principles for ISOs:

1. The ISO's governance should be structured in a fair and non-discriminatory manner.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic

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

[212] Approximately 300 filings to unbundle this category were filed by December 31, 1996.

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

[214] 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.

[216] *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.

information network consistent with the Commission's requirements.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

11. An ISO should establish an alternative dispute resolution (ADR) process to resolve disputes in the first instance.

Rehearing Requests

General Comments

NY Municipal Utilities argue that if the NYPP participants (or other tight pools) elect to establish an ISO, the ISO Principles should be made mandatory for the protection of transmission dependent utilities.

NY Com asks the Commission to clarify that it will allow flexibility to states and utilities in structuring proposals that meet the goals underlying the ISO principles. It explains that the parties to New York's electric competition proceeding are discussing the formation of an ISO in which transmission owners control the system operator, but would have to divest their competitive generation. NY Com further notes that it has not decided that matter yet, but it does not want to see such options foreclosed.

Minnesota P&L argues that certain functions, particularly those involving local area circumstances and safety, are better handled at the local level. It further argues that control area responsibilities of an ISO should focus on regional issues and operations, and on establishing and enforcing uniform criteria and guidelines for local control area operations in order to assure non-discriminatory treatment of all transmission customers.

AMP-Ohio asserts that the Commission should require the separation of transmission, generation and distribution through an ISO and, at a minimum, the Commission should include a Stage 3 of implementation to bring ISOs to reality.

ISO Principle 1

NYPP argues that the Commission should not include a rigid ban on transmission owner leadership in ISO governance because it is the transmission owner that is ultimately responsible for the reliability of the bulk power system.[218]

ISO Principle 2

NYPP asks that the Commission revise this principle to take a more flexible approach to significant employee issues. NYPP explains that it has 81 management employees on the payroll of individual member systems and that pension rights (accrual rights based on an average salary) and medical insurance (preexisting conditions) are through the individual member systems.

ISO Principle 3

SoCal Edison asks that this principle be revised to permit a separate access charge for each utility in order to avoid cost shifting. Anaheim seeks revision of this principle to require that an ISO provide comparable compensation to all transmission owners that make transmission facilities available for use by the ISO.

ISO Principle 5

Anaheim asks that this principle be revised to make clear that ISO arrangements should seek to encourage participation by all transmission owners within the region.

ISO Principle 6

NYPP seeks clarification that an ISO needs control over more than some generation facilities because the more generating facilities operating under an ISO the more reliability there is. Thus, it asserts that the Commission should clarify that its description of ISO control of generation does not require only a minimalist approach to ISO generation control.

ISO Principle 8

SoCal Edison seeks revision of this principle to remove the language linking the ISO to performing studies necessary to identify appropriate grid expansions. According to SoCal Edison, an ISO should not be a project sponsor or should not conduct planning studies to determine what facilities should be constructed because those actions would compromise its independence. In addition, SoCal Edison seeks revision of this principle to permit a transmission usage charge that incorporates locational marginal cost pricing for managing transmission congestion.

Commission Conclusion

We reaffirm our strong commitment to the concept of ISOs, and to the ISO principles described in Order No. 888. We continue to believe that properly structured ISOs can be an effective way to comply with the comparability requirements of open access transmission service. Nevertheless, we do not believe at this time that it is appropriate to require public utilities or power pools to establish ISOs, as suggested by AMP-Ohio. We think it is appropriate to permit some time to confirm whether functional unbundling will remedy undue discrimination before reconsidering our decision that ISO formation should be voluntary.

A number of the above rehearing requests on ISOs are from New York parties and deal with ongoing efforts in New York that would reform the New York Power Pool pooling agreements, restructure power markets, and possibly form an ISO. Some of these arguments are in apparent conflict; for example, the NY Municipal Utilities argue that the 11 ISO principles should be made mandatory if the New York Power Pool participants elect to establish an ISO, while the NY Com argues that the Commission should clarify Order No. 888 to state that it will allow flexibility to states and utilities in structuring proposals that meet the goals underlying the ISO principles. We note that since the time the rehearing requests were filed, the NY Power Pool has filed amendments to its pooling agreements on December 30, 1996 and also has filed, on January 31, 1997, various agreements and tariffs designed to implement an ISO and market exchange. To the extent the rehearing requests from New York parties deal with matters that have been filed with the Commission subsequent to the rehearing requests, the Commission will address the issues raised in the context of those filings.

In response to NY Com's request for clarification that we provide flexibility to states and their utilities in structuring ISO proposals, the Commission at this time clearly cannot, and does not intend to, prescribe a ''cookie cutter'' approach to ISOs. However, the Commission does believe that certain basic principles must be met to ensure non-discriminatory transmission services. We reaffirm our view that ISO Principles 1 (independence with respect to governance) and 2 (independence with respect to financial interests) are fundamental to ensuring that an ISO is truly independent and would not favor any class of transmission users. As the Commission stated in its recent order on the proposed PJM ISO:

> The principle of independence is the bedrock upon which the ISO must be built if stakeholders are to have confidence that it

[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.

will function in a manner consistent with this Commission's pro-competitive goals.[219]

ISO governance that is disproportionately influenced by transmission owners, unless they have fully divested their interests in generation, is not consistent with ISO Principle 1. We remain concerned that ISO proposals that do not include governance by a fair representation of all system users may not be independent, although we reserve final judgment on any specific governance structure until we have an opportunity to review a specific proposal.[220]

In response to the argument made by NYPP that transmission owner leadership in ISO governance may be needed because transmission owners are ultimately responsible for the reliability of the bulk power system, we emphasize that reliability is of primary importance to this Commission and that the formation and operation of an ISO should not in any way impair reliability. We believe that one of the main purposes of an ISO is to make an independent party, the ISO, responsible for at least short-term reliability. Even if both the transmission owners and the ISO will be responsible for some aspects of reliability, this does not affect our finding that the governance of the ISO must be independent of the transmission owners so that the ISO can carry out its own responsibilities in a not-unduly discriminatory manner.

In response to arguments of the NYPP that the Commission should revise Principle 2 to take a more flexible approach to employee issues, we reaffirm the necessity of requiring the employees of an ISO to be financially independent of market participants and note that Principle 2 suggests that a short transition period should be adequate for ISO employees to sever all financial ties with former transmission owners. We recognize that some flexibility may be necessary regarding the length of a transition period, but believe that ISO employees must in fairly short order be independent of all financial ties to any market participants, if we are to achieve not unduly discriminatory practices in generation and transmission markets.

A number of additional parties seek other revisions to or clarifications of the ISO Principles. For example, Minnesota P&L requests clarification or rehearing to ensure that the Commission provides sufficient flexibility to permit local operators, under the general supervision and control of the ISO, to perform local operational functions, such as performing switching operations. In response to this concern, we note that Principle 3 (open access under a single tariff) says that the portion of the transmission grid operated by a single ISO should be as large as possible. Our view, as described above, is that an ISO, which includes all affected users, should be responsible for operation of the system and ensuring reliability. The ISO may use some combination of actual physical control over facilities and virtual control of facilities by others (*i.e.*, the ISO exercises control over facilities by instructing the transmission owners' or generation owners' staffs as to the actions to be taken). The broad range of interested parties that establish the ISO must determine what services the ISO will perform and what services transmission owners or others will perform under ISO supervision.

We deny the requests by Socal Edison and Anaheim to revise ISO Principle 3 to permit separate access charges for each utility to avoid cost shifting. We think ISO Principle 3 already provides sufficient flexibility to accommodate the concerns of these parties with respect to design of access charges and compensation to owners for transmission facilities under operational control of the ISO.

Similarly, we see no reason to revise Principle 5 (control of interconnected operations) as requested by Anaheim. We agree with Anaheim that wide participation of transmission owners in a region will help ensure open access and increase efficient transmission coordination. ISO Principle 3 says that the portion of the transmission grid operated by a single ISO should be as large as possible. ISO Principle 5 says that an ISO should have control over the operation of interconnected transmission facilities within its region. These principles, as written, address Anaheim's concern.

With respect to NYPP's request for clarification of ISO Principle 6 (dealing with constraints), we note that the description of ISO Principle 6 in the Final Rule says that the ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system.[221] We do not think it is appropriate for the Commission to give further generic guidance now on what constitutes the proper level of operational control over generation. The ISO, including all stakeholders, needs to address this issue, based on the structure of power markets and perhaps other local considerations, in preparing a specific proposal for our approval.

Finally, we deny SoCal Edison's request for revision of ISO Principle 8 (pricing). In response to SoCal Edison's concern, ISO Principle 8 allows the use of appropriate locational marginal cost pricing. The principle allows flexibility regarding which regional organization of market participants (ISO or RTG) conducts the necessary studies to identify the need for expansion. We are unpersuaded by SoCal Edison's arguments that the fact that an ISO is involved in planning for transmission facility expansion would in any way compromise the independence of the ISO.

G. Pro Forma Tariff

In the Final Rule, the Commission combined the requirements for point-to-point transmission service and network transmission service into a single pro forma tariff.[222] The Commission explained that this eliminates many of the differences between the two NOPR pro forma tariffs, provides a unified set of definitions, and consolidates certain common requirements such as the obligation to provide ancillary services. The Commission also noted that it was issuing an accompanying Notice of Proposed Rulemaking in Docket No. RM96–11–000 in which it was seeking comments on whether a different form of open access tariff—one based solely on a capacity reservation system—might better accommodate competitive changes occurring in the industry while ensuring that all wholesale transmission service is provided in a fair and non-discriminatory manner.[223]

1. Tariff Provisions That Affect The Pricing Mechanism

a. Non-Price Terms and Conditions

In the Final Rule, the Commission explained that the Final Rule pro forma tariff is intended to *initiate* open access, with non-price terms and conditions based on the contract path model of power flows and embedded cost ratemaking.[224] It emphasized that the Final Rule pro forma tariff is not intended to signal a preference for contract path/embedded cost pricing for the future. The Commission indicated

[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.

[223] FERC Stats. & Regs. at 31,733; *mimeo* at 289.

[224] FERC Stats. & Regs. at 31,734–35; *mimeo* at 291–93.

that it will in the future entertain non-discriminatory tariff innovations to accommodate new pricing proposals.

The Commission further indicated that, by initially requiring a standardized tariff, it intends to foster broad access across multiple systems under standardized terms and conditions. However, the Commission emphasized that the tariff provides for certain deviations where it can be demonstrated that unique practices in a geographic region require modifications to the Final Rule pro forma tariff provisions.

Finally, the Commission stated that it will allow utilities to propose a single cost allocation method for network and point-to-point transmission services.

b. Network and Point-to-Point Customers' Uses of the System (so called ''Headroom'')

In the Final Rule, the Commission explained that it will not allow network customers to make off-system sales within the load-ratio transmission entitlement at no additional charge.[225] The Commission further explained that use of transmission by network customers for non-firm economy purchases, which are used to displace designated network resources, must be accorded a higher priority than non-firm point-to-point service and secondary point-to-point service under the tariff. In addition, the Commission found that off-system sales transactions, which are sales other than those to serve the transmission provider's native load or a network customer's load, must be made using point-to-point service on either a firm or non-firm basis. In rejecting the ''headroom'' concept (where a network customer can make off-system sales as long as its total use of the system does not exceed its coincident peak demand), the Commission explained that it was not requiring any utility to take network service to integrate resources and loads and if any transmission user (including the public utility) prefers to take flexible point-to-point service,[226] they are free to do so. Further, the Commission explained that any point-to-point customer may take advantage of the secondary, non-firm flexibility provided under point-to-point service equally, on an as-available basis.

Rehearing Requests

A number of entities argue that it is unreasonable to permit firm point-to-point customers to receive non-firm service, up to their contract demand, at no additional charge, at secondary receipt and delivery points, but to require transmission providers and network customers to purchase transmission for all off-system sales, including non-firm sales made in competition with sales made by the point-to-point customer.[227] FPL asserts that having built and paid for the entire transmission network, the owner and the network customer should have the flexibility to use the network as they need. Utilities For Improved Transition declare that just as the firm point-to-point customer is permitted to maximize the use of its contract demand, the transmission provider and network customer should be entitled to maximize their long-term fixed cost obligation (citing *AES Power, Inc.*, 69 FERC ¶ 61,345 at 62,300 (1994) (*AES*) for the proposition that the utility and its native load customers are obligated to pay all the costs of the transmission system without regard to the amount of energy actually scheduled).

FPL and Carolina P&L suggest two possible solutions: (1) allow the transmission provider and network customer to have rights to the headroom beneath their fixed cost obligations at no additional charge, or (2) restrict the no-charge use of firm point-to-point headroom to transmission service associated with non-firm purchases to serve load. Under either of these options, they assert, the firm point-to-point customer's rights to make non-firm off-system sales would be on an even competitive footing with the transmission provider or network customer.

PA Coops maintain that network customers should have the right to reassign/sell unused capacity below their 12-month rolling average peak demand at no additional charge. Cajun argues that network customers should be allowed to use the transmission system for non-firm (and perhaps firm) coordination transactions at no additional cost, provided the network customer's total use of the transmission system does not exceed its load ratio share. Cajun notes that the Commission seems to have determined elsewhere in the Rule that a network customer has already paid for the full use of its load ratio share (citing *mimeo* at 332 and 338). In addition, Cajun states that requiring the network customer to use point-to-point service results in the network customer paying twice for the same capacity.

VT DPS argues that the Commission should permit network users to make limited use of their network capacity to make off-peak off-system sales. It asserts that UtiliCorp's network tariff, filed in Docket No. ER95–203, provides a useful model: ''the level of capacity utilized by the company or the customer for its combined network load and off-system sales load would be fixed by the tariff as the highest coincident peak load experienced by the transmitting utility in the three years preceding the off-system sale.'' According to VT DPS, this places all firm users on a par. In contrast, VT DPS argues that the Commission's solution is arbitrary and patently inadequate. VT DPS claims that concerned parties are not just transmission providers, but include state agencies and entities that need to take network service. VT DPS further argues that the lower priority for secondary service under the point-to-point tariff may pose an unacceptable risk to public utilities with firm obligations to serve their load, and having to agree to a fixed demand quantity may be unsatisfactory for public utilities with growing customer loads and a statutory obligation to serve those loads.

LEPA argues that:

> [t]he Commission erred in not finding that in order to compete, one must be able to utilize base load units of 500MW size because entry without the ability to employ such base load units would make the putative entrant unable to compete; that in order to employ such units, or portions of them, the entrant had to engage in the coordinated development of base load units; that such coordinated development requires use of transmission for that purpose so as to be able to sell portions of the output of a baseload unit off-system, and that without 'headroom,' the cost of transmission for that purpose would not be comparable with the cost of transmission for the same purpose of the owner of the transmission. (LEPA at 5).

Commission Conclusion

The requests for rehearing on this issue present no arguments that were not fully considered in Order No. 888. Petitioners continue to claim that transmission providers and network customers are competitively disadvantaged vis-a-vis point-to-point transmission customers due to the point-to-point customers' ability to use as available, non-firm service over secondary points of receipt and delivery at no additional cost. The Commission attempted to strike a balance on this issue in Order No. 888 by allowing both network and point-to-point services to be priced on the same basis (*i.e.*, no longer summarily rejecting the use of the average of the 12 monthly system

[225] FERC Stats. & Regs. at 31,751; *mimeo* at 342–43.

[226] *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.

peaks as the denominator for the rate for point-to-point service). Additionally, the Commission established a lower priority for the non-firm secondary point-to-point service than for either economy purchases by network customers or for stand-alone non-firm point-to-point service, as discussed in Section IV.G.3.b. Accordingly, we believe that these concerns have been sufficiently addressed.

Furthermore, these entities want to be allowed to make off-system sales under their network service at no additional charge as long as their total use of the system does not exceed their load ratio share. They claim that it is inequitable not to allow such ''headroom'' sales under the network service while allowing firm point-to-point customers to use non-firm transmission service up to their contract demands using secondary receipt and delivery points at no additional charge. As the Commission stated in Order No. 888, customers are not obligated to take network transmission service.[228] If customers want to take advantage of the as-available, non-firm service over secondary points of receipt and delivery through the point-to-point service, they may elect to take firm point-to-point transmission service in lieu of the network service. We further note that transmission providers must take point-to-point transmission service for their own off-system sales, which results in comparable treatment for both the transmission provider and network customers. Transmission providers and other customers taking point-to-point transmission service do not need to be allowed to make ''headroom'' sales because they have access to as-available, non-firm service over secondary points of receipt and delivery at no additional charge through their point-to-point service.

Cajun's argument that a network customer has already paid for the full use of its load-ratio share of the system ignores the fact that network service is based on integrating a network customer's resources with its load, not on making off-system sales. This is why network customers pay for service on a load-ratio basis. If Cajun is concerned that it may need to pay for both network service and point-to-point service, Cajun can simply elect to take point-to-point service for all of its transmission needs.

VT DPS' claim that the lower priority accorded to transmission service to secondary points of receipt and delivery under flexible point-to-point service would present an ''unacceptable risk'' to public utilities is unsubstantiated. If the risk of having this secondary service curtailed is too great, this customer has the option to: (1) take stand-alone non-firm point-to-point service (which has a higher priority), (2) take this service on a firm point-to-point basis, or (3) take network service, which has a higher priority for economy purchases than either stand-alone non-firm or secondary non-firm point-to-point service.

With respect to LEPA's argument, the Commission has the goal of encouraging competition in the generation market, not discouraging generation competition by erecting barriers to entry such as arbitrary generator size. Furthermore, LEPA's argument that comparability is not achieved without allowing headroom is incorrect because both network customers as well as the transmission provider must obtain point-to-point transmission service to accommodate transmission for wholesale sales.

c. Load Ratio Sharing Allocation Mechanism for Network Service

In the Final Rule, the Commission concluded that the load ratio allocation method of pricing network service continues to be reasonable for purposes of initiating open access transmission.[229] The Commission also reaffirmed the use of a twelve monthly coincident peak (12 CP) allocation method because it believed the majority of utilities plan their systems to meet their twelve monthly peaks. However, the Commission stated that it would allow utilities to file another method (*e.g.*, annual system peak) if they demonstrate that it reflects their transmission system planning.

With respect to concerns raised about pancaked rates for network service provided to load served by more than one network service provider, the Commission indicated 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. However, customers that elect to do so, the Commission explained, must seek alternative transmission service for any such load that has not been designated as network load for network service. The Commission indicated that this option is also available to customers with load served by ''behind the meter'' generation [230] that seek to eliminate the load from their network load ratio calculation.

(1) Multiple Control Area Network Customers

Rehearing Requests

A number of entities argue that excluding load from the designation of Network Load does not solve the pancaking problem and results in the network customer paying even more transmission charges. They contend that a network customer must still pay two network charges and point-to-point charges to be able to operate its resources across two control areas. The Commission's approach, they argue, makes it impossible for a network customer with loads and resources in multiple control areas to integrate those loads and resources on an economic dispatch basis.[231] In essence, these entities state that a network customer must frequently dispatch resources in one transmission provider's control area (control area A) to serve that customer's load (in the case of a G&T cooperative, the load of a member system or third-party requirements customer) located in an adjacent control area of another transmission provider (control area B). As a result, they believe, the tariff essentially requires that network load in control area B, served by resources in control area A, must be counted as load in control area B. Alternatively, they believe that the tariff allows the transmission of resources in control area A to load in control area B as point-to-point transmission that requires an additional charge. These entities argue that either of these situations produces uneconomic results for multiple control-area network customers.

To avoid these problems, these entities propose that a network customer be allowed to use its network service to transmit power and energy from resources in control area A to serve load in control area B without designating the control area B load as network load for billing purposes. These entities suggest that no additional compensation should be required if such transfers to load in adjacent control areas plus other network transactions on behalf of the transmission customer in control area A do not exceed the customer's coincident demand in control area A. They also maintain that the ultimate solution is a regional system operated by an ISO. At the very least, TDU Systems contends, the Commission should require provision of service to network customers with loads and resources

[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.

located on multiple systems under a rate that recovers the customer's load ratio share—but no more—of the transmission owners' collective transmission investment in the control areas that the customer straddles.

AMP-Ohio maintains that rational economic transmission pricing policies demand elimination of the pancaking of rates caused by the arbitrary ownership boundaries of individual utilities.

TAPS asks that the Commission clarify that the Commission will look closely at how to create and promote region-wide rates when evaluating mergers and market-based rate proposals. It argues that the Commission should be receptive to section 211 filings seeking non-pancaked rates and should establish a Stage 3 for the purpose of addressing directly the need for transmission access on a non-pancaked, regional basis.

Commission Conclusion

In the Final Rule, the Commission addressed concerns regarding pancaked rates for network service for customers with load in multiple control areas.[232] Tariff section 31.3 allows a network customer the option to exclude all load from its designated network load that is outside the transmission provider's transmission system, and to serve such load using point-to-point transmission service.

NRECA and TDU Systems, however, argue that network customers located in multiple control areas should not have to pay for any additional point-to-point transmission service to make sales to non-designated load located in a separate control area. We disagree. Because the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service.

AMP-Ohio's concerns regarding ''arbitrary ownership boundaries of individual utilities,'' and TAP's proposal to require regional rates are beyond the scope of Order No. 888.[233] However, as the Commission explained in the Final Rule, it encourages the voluntary formation of regional transmission groups, as well as the establishment of regional ISOs, and will address those matters on a case-by-case basis.

(2) Twelve Monthly Coincident Peak v. Annual System Peak

Rehearing Requests

Several utilities ask that the Commission eliminate the requirement that charges for network service be calculated using a 12-month rolling average load ratio share and allow utilities discretion to determine the way network customers pay.[234] They assert that the requirement makes it impossible to recover the full cost of service when customers begin or terminate service. They suggest a unit charge based on a formula rate that is trued up each year or a month-by-month load ratio share calculation.

NE Public Power District states that the definition of load ratio share in section 1.16 of the pro forma tariff, taken together with sections 34.2 and 34.3 of the pro forma tariff require the use of the 12–CP method and the inclusion of losses to the generator bus. This, it argues, is inconsistent with the Commission's statement that ''[u]tilities that plan their systems to meet an annual system peak * * * are free to file another method if they demonstrate that it reflects their transmission system planning.'' (NE Public Power District at 22–23). NE Public Power District argues that utilities should be allowed to use CP demands measured at delivery points at some common specified voltage. It further asks the Commission to clarify whether the monthly peak includes or excludes transmission losses.

EEI and AEP argue that transmission reservations for services of less than one month's duration and any discounted firm transactions should not be counted in the load ratio calculation when determining the 12 CP on point-to-point rates, but that the revenues from these services should be credited to all firm transmission users.

Montana Power argues that the Commission's pricing approach discriminates against native load customers because all non-network uses of the system do not occur at full, non-discounted prices for the entire month and the effects of discounts will be shouldered by native load customers. According to Montana Power, this is a disincentive to utilities to offer discounts and creates a possibility of gaming by network customers buying one day firm point-to-point reservations to reduce their network load ratio shares.

Commission Conclusion

While the Commission reaffirmed the use of a twelve monthly coincident peak (12 CP) allocation method for pricing network service in the Final Rule, the Commission also stated:

> [u]tilities that plan their systems to meet an annual system peak * * * are free to file another method if they demonstrate that it reflects their transmission system planning.[235]

Accordingly, utilities are free to propose in a section 205 filing an alternative to the use of the 12-month rolling average (e.g., annual system peak) in the load ratio share calculation, subject to demonstrating that such alternative is consistent with the utility's transmission system planning and would not result in overcollection of the utility's revenue requirement. Any proposed alternative would also be subject to any future filing conditions established by the Commission.[236]

We also are not convinced that we should require the calculation of load ratios using a particular method on a generic basis. Any such proposals, including those concerning the treatment of discounted firm transmission transactions in the load ratio calculation and revenue credits associated with such transactions, are best resolved on a fact-specific, case-by-case basis.

Finally, the Final Rule does not prohibit utilities from ''us[ing] CP demands measured at delivery points at some common specified voltage'' as claimed by NE Public Power District. Treatment of transmission losses can be accomplished in different ways by different transmission providers under the pro forma tariff, such as adjustment to a consistently applied voltage level.

Regarding NE Public Power District's allegation that certain sections of the pro forma tariff do not allow the use of the annual system peak method in the load ratio share calculation, the Commission recognizes that certain rate methodologies may require minor adjustments to the non-price terms and conditions to be consistent with the proposed rate methodology. However, any modifications to the non-price terms and conditions established in the pro forma tariff must be fully supported by the utility and the appropriateness of such proposed changes will be evaluated by the Commission for

[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.

consistency with the proposed rates or rate methodologies. The remainder of NE Public Power District's concerns are case-specific and should be raised by NE Public Power District at such time as a transmission provider makes a filing.

(3) Load and Generation ''Behind the Meter''

Rehearing Requests

Several entities request clarification[237] concerning the definition of Network Load in pro forma tariff section 1.22, which provides, in pertinent part, that:

A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery.

These entities maintain that section 1.22 is too restrictive and is inconsistent with the Final Rule's treatment of load served from ''behind the meter'' generation.[238] Specifically, these entities request that the Commission clarify that a network customer can exclude from its designated network load a portion of load at a discrete point of delivery, which is served from generation behind the meter. In support of this position, a number of petitioners cite to *FMPA* v. *FPL*, 74 FERC ¶ 61,006 at 61,012–13, in which they claim the Commission allowed network customers to exclude load served by behind the meter generation.[239]

TAPS asserts that there is no operational or economic reason to require the designation of all load at a discrete point of delivery as network load.

FMPA argues that network customers should not be charged a network rate to use their own transmission (or distribution) system to serve loads that are located beyond the transmission owner's system. FMPA interprets the Final Rule on this issue as allowing a network customer that has behind-the-meter generation to serve part of its behind the meter load from such generation; thus, a customer can exclude that load, which is served without using the transmission provider's transmission system, from the load ratio share. FMPA's interpretation of section 1.22 is that ''a network customer may not import power using both point-to-point and network transmission service at the same delivery point, but that this Section does not prevent a network customer from serving load from generation when both are behind the delivery point and when the transaction does not rely upon use of the transmission provider's transmission system.'' (FMPA at 5). FMPA requests that the Commission clarify the language in section 1.22 consistent with its interpretation above.

Michigan Systems asks the Commission to modify section 1.22 because the ''clause may be interpreted to require network integration transmission service customers to pay a second time for the transmission of power that is already being transmitted under other arrangements, such as transmission ownership. The clause could also be interpreted to allow the transmission provider to charge customers for the transmission of power which does not use the transmitter's system, such as for transmission from 'behind the meter' generation to 'behind the meter' load.'' (Michigan Systems at 5–13).

Wisconsin Municipals ask the Commission to ''clarify that a partial designation is appropriate if (1) only part of the load behind a particular delivery point relies upon the transmission provider's transmission system for service or (2) a network customer is responsible for serving only a portion of the load behind a discrete delivery point.'' (Wisconsin Municipals at 17–18).

Blue Ridge asks the Commission to clarify that it intended to allow for multiple ownership of resources by customers who are not network customers.

Utility Position

FPL and Carolina P&L ask the Commission to clarify that section 1.22 and the Rule (*see also* Original Sheet No. 94 and *FMPA I*, 67 FERC ¶ 61,167 at 61,481–82 (1994)) mean that regardless of whether or not a customer has behind the meter or local generation at a delivery point, if a customer wants to purchase network service to serve load at a delivery point, it must purchase network service for all such load—the customer cannot split the load into network and point-to-point components at a specific point of delivery.[240] Otherwise, FPL states, there would be a split system with the potential to game the system and problems with how it would work.

AEP argues that the option in section 1.22 of excluding load from network load should be deleted. AEP states that, as the Commission recognized in its original *FMPA* v. *FPL* order, the provision is contrary to the comparability standard. Specifically, AEP argues that transmission-owning utilities do not and cannot offer themselves partial integration service electing to pay only a portion of the network costs, but rather must pay for the entire network, which integrates all of the transmission-owning utility's resources and loads. According to AEP, the load served by behind-the-meter generation is not isolated from the system, which is there to serve that load when the behind-the-meter generation is unavailable. Allowing a network customer to use short-term non-firm point-to-point transmission, AEP asserts, allows customers to evade a large portion of the network's costs, which they will do on an unconstrained system such as AEP.

Commission Conclusion

We disagree that the prohibition in tariff section 1.22 against a network customer designating only part of a load at a discrete point of delivery as network load is either inconsistent with the Final Rule's treatment of generation ''behind the meter'' or is contrary to the Commission's decisions in *FMPA I* and *FMPA II*.

The Commission addressed ''behind the meter'' generation in the Final Rule as follows:

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. [citing *Florida Municipal Power Agency* v. *Florida Power & Light Company*, 74 FERC ¶ 61,006 (1996), *reh'g pending.*] 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.[241]

Implicit in the Commission's discussion of this issue in the Final Rule and also in *FMPA I* and *FMPA II*, in permitting

[237] *E.g.*, AMP-Ohio, TAPS.

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

[239] *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.

the ''exclusion of a particular load,'' is that the Commission will allow a network customer to exclude the *entirety* of a discrete load from network load, but not just a portion of the load served by generation behind the meter.

In its request for rehearing of *FMPA I*, FMPA requested that the Commission confirm its interpretation of the Commission's finding in *FMPA I* that:

[FMPA] can choose to serve an *amount* of load in a city from generation in the city, so long as FMPA does not sometimes serve that level of load from external generation or use that generation to serve member loads outside the city.[242]

On rehearing in FMPA II, the Commission did not grant FMPA's request to allow a partial designation of network load. Furthermore, the Commission provided an example of how FMPA could request that certain of its loads and resources be excluded from network integration transmission service. The Commission explained that FMPA could choose to exclude the loads of the cities of Ft. Pierce and Vero Beach from the request for network integrated transmission service and alternatively request point-to-point transmission service to transmit power from resources in those cities to other FMPA members or from FMPA member cities to Ft. Pierce and Vero Beach.[243] The Commission neither stated that it would allow a partial designation of a discrete load as network load nor provided any examples of such treatment.

Additionally, throughout the pro forma tariff, network customers are consistently prohibited from designating only a portion of a discrete network load. For example, tariff section 31.2 provides:

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. [Emphasis added]

Accordingly, we find that no inconsistency exists between the tariff language and either the language in the Final Rule or the Commission's findings in *FMPA I* or *FMPA II*.

In support of its position to allow a partial designation of network load at a point of delivery, TAPS claims that there are no operational reasons to require the designation of all load at a discrete point of delivery as network load. We disagree. Utilities, both commenting on the NOPR and on rehearing (*e.g.*, AEP rehearing at 19–20 and Florida Power & Light at 14–18), express concern that customers allowed to divide a discrete load between point-to-point and network services would create a ''split system.'' The concept of allowing a ''split system'' or splitting a discrete load is antithetical to the concept of network service. A request for network service is a request for the *integration* of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated—it is either fully integrated or not integrated. Furthermore, such a split system creates the potential for a customer to ''game the system'' thereby evading some or all of its load-ratio cost responsibility for network services.[244]

For example, FMPA asserts that if a FMPA member city has a peak load of 100 MW and behind the meter generation of 75 MW, FMPA should be allowed to designate a portion of its load as network load (*e.g.*, 60 MW), and to serve the remaining load (*e.g.*, 40 MW) from its behind-the-meter generation.[245] However, as a number of utilities note, this would lead to the possibility of gaming the system. For example, if at the time of the monthly system peak the FMPA member city generates more than 40 MW (or takes short-term firm transmission service (or a combination of the two)), it may be able to lower its monthly coincident peak load for network billing purposes,[246] and thereby reducing if not eliminating its load-ratio cost responsibility for network service. Because network and native load customers bear any residual system costs on a load-ratio basis, any cost responsibility evaded by a network customer in this manner would be borne by the remaining network customers and native load.

FPL also raises several fundamental operational problems associated with allowing partial network service or creating a ''split system:''

If all the loads are included in a single control area, how does the transmission provider know what portion of the power delivered is serving the point-to-point load (which presumably would not be counted toward the network's load ratio)?

Using the same 100 MW load example previously mentioned where there is a 40/60 network/point-to-point split, there would have to be a determination of how the split would be done in non-peak situations. Are the first 40 MW of load all network load, or all point-to-point load, or split on a 40/60 basis?

If the system purchases economy power from non-local resources, how is that delivery allocated between the network portion (for which there would be no point-to-point scheduling, curtailment, or transmission charges) and the point-to-point portion (which must be arranged and paid for separately under a point-to-point tariff)?

The bottom line is that all potential transmission customers, including those with generation behind the meter, must choose between network integration transmission service or point-to-point transmission service. Each of these services has its own advantages and risks.[247]

In choosing between network and point-to-point transmission services, the potential customer must assess the degree of risk that it is willing to accept associated with the availability of firm transmission capacity. Customers choosing point-to-point service, based solely on the amount of transmission capacity reserved (or contract demand), may face a relatively higher risk associated with the availability of firm transmission capacity. For example, if a customer with a peak load of 100 MW, and behind the meter generation of 75 MW, chooses to serve a portion of its load with point-to-point transmission service (*e.g.*, 60 MW) and the remaining load (*e.g.*, 40 MW) with its behind-the-meter generation, this customer faces the risk that, should its generation behind the meter become unavailable, the transmission provider may not have firm transmission capacity available to serve the remaining 40 MW of that

[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.

[246] 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.

customer's load. One way to minimize this risk would be for the customer to reserve and pay for additional firm point-to-point transmission service to protect against the unavailability of its behind-the-meter generation. Alternatively, the customer could choose network service in which the transmission provider will plan and provide for firm transmission capacity sufficient to meet the customer's current and projected peak loads, including integration of the customer's behind-the-meter generation as a network resource.

For the reasons stated above, a network customer will not be permitted to take a combination of both network and point-to-point transmission services under the pro forma tariff to serve the same discrete load. Accordingly, the requests for rehearing to modify tariff section 1.22 are hereby rejected.

Moreover, the Commission will allow a network customer to either designate all of a discrete load [248] 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.[249]

(4) Existing Transmission Arrangements associated with Generating Capacity Entitlements (*e.g.*, ''preference power'' customers of PMAs)

Rehearing Requests

Several entities argue that section 1.22 of the pro forma tariff is arbitrary and cannot be reconciled with the Final Rule's determination not to abrogate existing agreements. [250]

Specifically, several transmission customers claim that the prohibition against designating only part of the load at a discrete point of delivery is problematic for customers with existing transmission arrangements for receiving preference power or capacity entitlements from power marketing agencies (PMAs). For example, Central Minnesota Municipal argues that the limiting language of section 1.22 should be eliminated as it would preclude Mountain Lake (a member of Central Minnesota Municipal) from using network transmission and, at the same time, point-to-point transmission for WAPA power under a separate arrangement. These transmission customers assert that if they designate all of the load at a discrete point of delivery as network load, and pay for such network load on a load-ratio basis, then the transmission provider is paid twice for the same transmission service—once through the existing transmission arrangement and a second time through the network service.

NRECA and TDU Systems argue that if a customer chooses to use network service under the pro forma tariff to supplement its existing arrangements to meet future full requirements, the Commission should amend section 1.22 so the transmission provider cannot overcharge the customer:

> A Network Customer may elect to designate less than its total load as Network Load. Where a Network Customer has elected not to designate a particular load as a Network Load, the Network Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-to-Point Transmission Service that may be necessary for such non-designated load, unless such non-designated load is served pursuant to other arrangements. [251]

Alternatively, the transmission customer may choose not to designate any load at a discrete point of delivery as network load. However, these transmission customers note that the preference power allotments received from PMAs typically do not equal the total load of a customer at a discrete point of delivery. Therefore, the customer would need to acquire additional point-to-point transmission service for any remaining transmission needs. Accordingly, these transmission customers conclude that the existence of their current transmission arrangements precludes them from receiving network service which they claim does not allow the comparable use of the system that the transmission provider enjoys.

Commission Conclusion

The Commission recognizes that existing power and transmission arrangements represent a transitional problem as customers begin to take service under the pro forma tariff. Clearly, the Commission did not intend for a transmission provider to receive two payments for providing service to the same portion of a transmission customer's load. Any such double recovery is unacceptable and inconsistent with cost causation principles. Neither did the Commission intend to allow a transmission customer to designate less than its total load as network load at a discrete point of delivery even though a portion of that load is served under a pre-existing contract. We clarify that such a transmission customer has several alternatives it can pursue using either point-to-point or network transmission service.

Using network transmission service, the network customer would designate its existing generation supply contract(s) as a network resource(s) and the associated load served under such contract(s) designated as network load. The network customer then has two options: pursue negotiations with the transmission provider to obtain a credit on its network service bill for any separate transmission arrangements or for the unbundled transmission rate component of the existing generation supply contract or (2) seek to have any separate transmission or the unbundled transmission rate component of its generation supply contract eliminated in recognition of the network transmission service now being provided and paid for under the tariff.[252]

Using point-to-point transmission service, the transmission customer would identify the discrete points of delivery being served under existing generation supply and existing transmission contracts and acquire additional point-to-point transmission service under the tariff for any remaining load at those discrete points of delivery.

Any of these three alternatives should address concerns regarding the possibility of double recovery. Furthermore, a transmission customer may file a complaint under section 206 with the Commission to address any claims of double recovery that it is unable to resolve with the transmission provider.

d. Annual System Peak Pricing for Flexible Point-to-Point Service

In the Final Rule, the Commission indicated that it will allow a transmission provider to propose a formula rate that assigns costs

[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.

[249] 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.

consistently to firm point-to-point and network services.[253] The Commission added that it will no longer summarily reject a firm point-to-point transmission rate developed by using the average of the 12 monthly system peaks.

The Commission explained that it still believed that it was appropriate for utilities to use a customer-specific allocated cost of service to account for diversity, but based on the changed circumstances since *Southern Company Services, Inc.*, 61 FERC ¶ 61,339 (1992) (*Southern*), it indicated that it would now permit an alternative. Thus, the Commission indicated that it will allow all firm transmission rates, including those for flexible point-to-point service, to be based on adjusted system monthly peak loads.

In order to prevent over-recovery of costs for those who use this approach, the Commission explained that it will require transmission providers to include firm point-to-point capacity reservations in the derivation of their load ratio calculations for billings under network service. In addition, the Commission explained that revenue from non-firm transmission services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates. The Commission noted that the combination of allocating costs to firm point-to-point service and the use of a revenue credit for non-firm transmission service will satisfy the requirements of a conforming rate proposal enunciated in our Transmission Pricing Policy Statement.[254]

Rehearing Requests

Blue Ridge maintains:

> The sea change in the Commission's approach to the pricing of transmission services is not warranted by any claimed change in circumstances and Blue Ridge accordingly requests rehearing and rejection of the new approach. At a minimum, the Commission should clarify that any deviation from use of an annual peak divisor (or other methodology based on system capability) for setting point-to-point transmission rates will be considered only on a case-by-case basis.

TAPS also argues that the use of the same denominator for two different services is inconsistent, unjust and discriminatory. It asserts that the Commission should use a system capability divisor for allocating fixed costs between reservation-based and load-based firm service.

TAPS also asserts that most utilities plan their transmission systems to cover the annual system peak estimated conservatively on the higher side in order to meet unusually high loads reliably, rather than planning on the basis of the twelve monthly peaks as stated in Order No. 888. Therefore, TAPS asks that the Commission maintain 1 CP pricing for point-to-point service. TAPS argues that the Commission should allow transmission providers and customers to demonstrate the appropriate measure for each transmission system's capability in utility-specific proceedings.

If the Commission uses a 12 CP denominator, TAPS requests that the Commission clarify that capacity reservations should be established consistently with that denominator and should recognize the inappropriateness of using such rates as a cap for non-firm rates. It asserts that non-firm rates should be limited to actual variable costs of transmission, plus losses, plus a modest adder as a contribution toward fixed costs. At the very least, TAPS argues that the cap should be developed using a more appropriate denominator, *e.g.*, system capability.

TAPS further argues that if the rate divisor is based on experienced 12 CP, the capacity reservations and the divisor should be measured at the delivery points (as it is for native load customers), not the higher of the receipt or delivery points, to avoid a mismatch between the rate divisor and billing determinants.[255]

Wisconsin Municipals and TAPS argue that if a 12 CP divisor is used, customers must have the flexibility to vary their monthly nomination under the point-to-point tariff.

Commission Conclusion

With respect to TAPS argument that the annual system peak method would be appropriate for most systems, the Commission has determined in Order No. 888 that this issue is best resolved on a case-by-case basis and specifically provided utilities the opportunity to propose to use other allocation methods, including the annual system peak method sought by TAPS.[256]

The Commission already recognized the potential for a mismatch between the rate divisor and billing determinants that TAPS now raises on rehearing. We explicitly stated in the Final Rule that

> [t]he adjusted system monthly peak loads consist of the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with all firm point-to-point service customers plus the monthly contract demand reservations for all firm point-to-point service.[257]

Use of the adjusted system monthly peak loads in the rate divisor for flexible point-to-point transmission service eliminates the mismatch concern raised by TAPS.

We have also fully addressed in the Final Rule those arguments objecting to the use of the average of the 12 monthly peaks in determining a firm point-to-point transmission rate and no further discussion is required. The other arguments raised with respect to this section are fact specific and best addressed in individual rate proceedings where the use of an annual system peak versus an average of the 12 monthly peaks in determining a firm point-to-point transmission rate is more appropriately evaluated.

e. Opportunity Cost Pricing

(1) Recovery of Opportunity Costs

The Commission emphasized in the Final Rule that it had fully explained its rationale for allowing utilities to charge opportunity costs in *Northeast Utilities* and *Penelec*.[258] The Commission also explained that transmission providers proposing to recover opportunity costs must adhere to the following requirements:

(1) A fully developed formula describing the derivation of opportunity costs must be attached as an appendix to their proposed tariff;

(2) Proposals must address how they will be consistent with comparability; and

(3) All information necessary to calculate and verify opportunity costs must be made available to the transmission customer.

Rehearing Requests

VT DPS disputes the Commission's holding with respect to opportunity costs and argues that rate filings seeking recovery of opportunity costs should be summarily rejected. It asserts that, contrary to statements by the Commission, courts have not endorsed opportunity cost pricing for transmission customers and maintains that the Commission's failure to consider objections to opportunity cost

[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).

pricing on the merits ‘‘directly flouts the court’s ruling’’ in *Northeast Utilities.* According to VT DPS, opportunity costs are inherently unverifiable: ‘‘there are insuperable difficulties in proving the existence of lost opportunity costs in any fashion which can readily and objectively be applied.’’ At a minimum, VT DPS asserts, opportunity costs arising more than five years out are unverifiable and should not be permitted. Moreover, VT DPS argues that the right to challenge the verifiability of opportunity costs is not adequate protection because it is wasteful and burdensome (citing *Cajun Electric Power Cooperative* v. *FERC,* 28 F.3d 173 at 179 (D.C. Cir. 1994) (*Cajun*)).

VT DPS also asserts that the Commission’s treatment is inconsistent with its treatment of gas pipeline pricing policies, which do not permit the assessment of opportunity costs in gas pipeline transportation rates. In addition, VT DPS asserts that opportunity cost pricing for firm transportation service would allow the transmitting utility to charge more for firm transmission of a third party’s power supplies than it charges its own native load for the transmission component of native load service. Finally, VT DPS claims that opportunity cost pricing contravenes Cajun because opportunity cost pricing has a chilling effect on competition in New England and nationally. VT DPS challenges whether a tariff provision that permits the imposition of opportunity costs ‘‘precludes the mitigation of [a utility’s] market power.’’

CCEM asserts that there is no justification for allowing opportunity cost charges when such charges can be eliminated in the secondary or released capacity market, without the discriminatory charge. It notes that opportunity costs are not allowed in any other industry and the Commission should not allow recovery of lost profits.

American Forest & Paper argues that the only way to ensure comparability is to require that transmission services are priced for all customers based upon embedded cost principles (including pricing for expansions). It opposes opportunity cost pricing as being discriminatory because wheeling customers are required to compensate the transmitting utility for its lost opportunities to make economy purchases or sales to benefit native load. It further argues that transmission capacity was not designed to facilitate non-firm, unplanned economy purchases or sales on behalf of native load. American Forest & Paper also asserts that allowing redispatch costs incorrectly presupposes that native load has a superior right to the transmission system. According to American Forest & Paper, neither of these costs (opportunity/redispatch) should be imposed on the former sales, now transmission-only, customers—the transmission customer is no more responsible for the alleged transmission constraint than the existing native load customer who adds to its requirements or the new customer locating in the service territory. It maintains that firm transmission contracts cannot by definition displace opportunity sales because there is no ‘‘opportunity’’ until there is capacity in excess of the firm transmission contractual commitments. In addition, American Forest & Paper asserts that opportunity cost pricing may create difficulties for IPPs, *i.e.*, a lender may not finance projects because of cost uncertainty related to varying revenue flows caused by opportunity cost pricing. It believes that utilities should be required to establish a separate subsidiary to make opportunity purchases or sales on its behalf, which may minimize self dealing.[259] It further asserts that expansions should be subject to embedded cost pricing—unlike in gas pipeline expansions, electric transmission expansions invariably affect an integrated network.

CCEM asserts that, if opportunity cost pricing is maintained, transmission customers should be given the information they need to avert or mitigate opportunity-cost exposure. In particular, it argues that customers need information on the run status and cost of generating units that the transmission provider controls in advance of any proposed redispatch. In addition, CCEM argues that transmission providers should be required to inform customers of a redispatch in advance.

Commission Conclusion

As an initial matter, many of the arguments raised are collateral attacks on *Penelec, Northeast Utilities,* and the Commission’s Transmission Pricing Policy Statement. These matters are not the subject of this proceeding, but rather Order No. 888 simply applies the policy already in place. Therefore, these arguments are not properly raised in this proceeding.[260]

The Commission does not believe that any changes are necessary to its policy on opportunity cost recovery.[261] In the Final Rule, we fully explained our rationale for allowing utilities to charge opportunity costs and no arguments have been presented on rehearing that would persuade us otherwise.

As has been our policy, we will continue to determine the appropriateness of opportunity cost pricing proposals on a case-by-case basis. We continue to believe that opportunity cost pricing will promote efficient decision-making by both transmission owners and users and will not result in unduly discriminatory or anticompetitive pricing. We have stated that because any transmission pricing proposal must meet the comparability standard, we will have ample opportunity to address any concerns that opportunity cost pricing may be unfair and anticompetitive or otherwise inconsistent with the comparability standard, including those concerns raised by CCEM with respect to the need for advance information as to any proposed redispatch.

We note that in compliance filings made pursuant to Order No. 888, most utilities did not make the tariff changes necessary to charge opportunity costs to customers under the pro forma tariff. Absent a subsequent section 205 filing, these transmission providers will not be able to charge opportunity costs under their compliance tariffs. Where transmission providers did modify their tariff to allow for opportunity costs, the Commission is reviewing the proposed charges on a case-by-case basis.

(2) Redispatch Costs

In the Final Rule, the Commission clarified that redispatch is required only if it can be achieved while maintaining

[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).

reliable operation of the transmission system in accordance with prudent utility practice.[262]

The Commission further explained that the recovery of redispatch costs requires that: (1) a formal redispatch protocol be developed and made available to all customers; and (2) all information necessary to calculate redispatch costs be made available to the customer for audit. The Commission also noted that the rates proposed must meet the standards for conforming proposals in the Transmission Pricing Policy Statement.

The Commission also explained in the Final Rule that if the transmission provider proposes to separately collect redispatch costs on a direct assignment basis from a specific transmission customer, the transmission provider must credit these revenues to the cost of fuel and purchased power expense included in its wholesale fuel adjustment clause.[263]

Rehearing Requests

TAPS asserts that there is too much uncertainty with respect to the treatment of redispatch costs. It asserts that the Commission should require a section 205 filing for each corridor/constraint for which redispatch costs are intended to be shared among the transmission provider and network customers. Once there has been a determination regarding a particular corridor/constraint, TAPS argues that ''it would be appropriate to charge network customers for redispatch costs through a mechanism with no fewer protections than a fuel clause.'' It further argues that redispatch costs, like opportunity costs, should be capped at the cost of the upgrade and, at the least, the Commission should clarify that application of the redispatch sharing provision should be adjudicated in particular cases.

TDU Systems states that it does not object to a redispatch obligation that is necessary to ensure transmission system reliability, but they object to the fact that a transmission provider can determine that a transmission constraint will arise as a result of the sale of additional firm transmission service by the transmission provider. It asks the Commission to clarify that the transmission constraint that would trigger a redispatch obligation cannot be caused by a transmission provider's sale of additional firm transmission capability.

Wisconsin Municipals asks the Commission to clarify that recovery of redispatch costs on a load ratio basis, without a section 205 filing, is limited to when such action is necessary for reliability reasons alone (not for economic reasons), and that in all other circumstances a section 205 filing must be made and costs directly assigned to the customer receiving the economic benefit of the redispatch. It further asserts that if redispatch is allowed for economic reasons, it must be offered on a comparable, non-discriminatory basis to all customers and the transmission provider, provided the beneficiary agrees to accept a direct assignment.

Several utilities argue that redispatch costs are a subset of opportunity costs and that the Commission should not use both terms in the tariff because it implies different standards apply to transmission providers and their customers (*e.g.,* sections 23.1 and 27).[264] They request that the Commission only use the term ''redispatch costs'' in the pro forma tariff and impose the same redispatch obligations on network customers as are imposed on transmission providers.

No rehearing requests addressed the subject of fuel adjustment clause treatment for redispatch costs.

Commission Conclusion

The Commission believes that the obligation to create additional transmission capacity to accommodate a request for firm transmission service should properly lie with the transmission provider, not a network customer.

The Commission clearly established in the Final Rule that utilities are to be given ''substantial flexibility * * * to propose appropriate pricing terms, including opportunity cost pricing [of which redispatch costs are a subset], in their compliance tariff.'' [265] The Commission further required that any such rate proposals must meet the standards for conforming proposals in the Transmission Pricing Policy Statement. Accordingly, TAPS is free to pursue its concerns in any relevant compliance filings.

Tariff sections 33.2 and 33.3 clearly establish that redispatch of all Network Resources and the transmission provider's own resources are only to be performed to maintain the reliability of the transmission system, not for economic reasons. Such costs are to be shared between network customers and the transmission provider on a load ratio basis. Similarly, the Commission clarified in Order No. 888, in modifying the transmission customer's redispatch obligation, that such change was ''to limit the redispatch obligation to reliability reasons.'' [266] Therefore, no further clarification is necessary.

Other redispatching provisions under the tariff (*e.g.,* sections 13.5 and 27) refer to situations where the transmission provider can relieve a system constraint more economically by redispatching the transmission provider's resources than through constructing Network Upgrades in order to provide the requested transmission service. However, in this circumstance, redispatch is conditioned upon the eligible customer agreeing to compensate the transmission provider for such redispatch costs. Section 13.5 of the pro forma tariff further requires that any such redispatch costs to be charged to the transmission customer on an incremental basis must be specified in the customer's service agreement prior to initiating service. These tariff requirements would appear to satisfy Wisconsin Municipals concerns because a section 205 filing must be made to directly assign costs to the customer receiving the economic benefit of the redispatch.

Regarding the argument that only the term ''redispatch costs'' should be used in the pro forma tariff, we note that the Commission followed this suggestion in drafting the pro forma tariff. The only exception is the use of opportunity costs in section 23.1 of the tariff, which caps the compensation for resellers at the higher of: (1) the original rate, (2) the transmission provider's maximum rate on file at the time of the assignment or (3) the reseller's opportunity cost. We further note that their concerns that different standards may be applied to transmission providers than to their customers are addressed in section IV.C.6 (Capacity Reassignment).

f. Expansion Costs

In the Final Rule, the Commission allowed transmission providers to propose any method of collecting expansion costs that is consistent with the Commission's transmission pricing policy.[267] The Commission explained that ''or'' pricing sends the proper price signal to customers and promotes efficiency and further indicated that ''and'' pricing will not be allowed.

The Commission also indicated that any request to recover future expansion

[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.

costs will require a separate section 205 filing.

Rehearing Requests

Several entities argue that requiring section 205 filings for all transmission expansion costs would impose difficult burdens on transmission providers that use formula rates because they would have to try to distinguish between replacement costs, which are included in formula rates, and expansion costs, which are not.[268] They assert that section 205 filings should be required only for system expansion costs that the transmission provider proposes to recover on a direct assignment or incremental cost basis, but not for costs to be recovered on an embedded cost basis.

TDU Systems maintain that to the extent Order No. 888's provisions concerning direct assignment of transmission facilities indicate a change in the historic policy of rolling transmission investments into rate base, there is a risk TDUs will bear a disproportionate share of the transmission burden relative to transmission owners under the Commission's ''or'' pricing policy. According to TDU Systems, transmission owners should be required to permit customers to substitute their own lower cost capital for that of the owner's.

SoCal Edison and Carolina P&L ask the Commission to clarify that a transmission provider has no obligation to build or upgrade its facilities for short-term firm point-to-point transmission customers (§§ 13.5, 15.4 and 1.13). SoCal Edison states that if a transmission provider is required to build, the Commission should clarify that any costs must be directly assigned to the requesting customer.

Commission Conclusion

The Final Rule does not change the Commission's filing requirements for recovery of transmission expansion costs or other transmission-related expenses. The Rule does not impose a section 205 filing requirement to the extent that existing formula rates do not require that such a filing be made to add transmission investment. However, consistent with the Commission's transmission pricing principles in effect prior to Order No. 888, a decision to price transmission on an incremental cost basis, or to directly assign facilities, are cost assignments that require a section 205 filing.

The Final Rule also does not change the Commission's transmission pricing policies. Under our transmission pricing policy, a utility is still permitted to charge the higher of incremental expansion costs ''or'' a rolled-in embedded cost rate. There is no bias in the Final Rule that should cause TDU customers or any other customer to pay a disproportionate share of transmission costs. Moreover, we note that we also encourage joint planning/building options and regional solutions such as RTGs and ISOs.

We do not believe that any change is necessary with regard to the obligation to build or expand. While both sections 13.5 and 15.4 obligate the transmission provider to expand or upgrade its transmission system to accommodate an application for firm point-to-point transmission service, these sections are conditioned upon the transmission customer agreeing to compensate the transmission provider for such upgrade. In light of this compensation requirement, we do not anticipate that transmission providers will be requested to upgrade facilities in order to accommodate requests for short-term point-to-point transmission service. However, in the unlikely event that a short-term firm point-to-point transmission customer agrees to pay the costs of such upgrades, we believe that it is appropriate to require a transmission provider to expand its system to accommodate the request.

g. Credit for Customers' Transmission Facilities

In the Final Rule, the Commission concluded that credits related to customer-owned facilities are more appropriately addressed on a case-by-case basis, where individual claims for credits may be evaluated against a specific set of facts.[269] The Commission stressed 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 Commission further explained that it must be *demonstrated* that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider in order to establish a right to credits. The Commission also noted that consistent with its ruling in *FMPA II*,[270] if a customer wishes not to integrate certain loads and resources, and thereby exclude them from its load ratio share of the allocated cost of the integrated system, it may do so by separately contracting for point-to-point transmission service.

Rehearing Requests

APPA asserts that several differences between the treatment of transmission customers' and transmission providers' facilities are not comparable and must be corrected: (1) transmission providers' facilities include those owned, controlled or operated by the transmission provider, but to obtain credit, transmission customers must own the facilities; (2) transmission providers are under no obligation to engage in joint planning and historically have refused, thus putting the matter beyond the control of the customer; and (3) facilities of the customer must serve all of the transmission provider's power and transmission customers, but a transmission provider can include facilities in rates that serve only certain customers. APPA also maintains that the Commission failed to provide sufficient guidance to allow customers to ascertain the type of transmission facilities for which they can expect to receive credit.

Several entities assert that the standard as to existing customer-owned facilities is inherently ambiguous—the Final Rule preamble says integrated into the ''plans *or* operations'' of the transmitting utility, but section 30.9 of the tariff says the ''planning and operations'' of the transmission provider (emphasis added).[271] Further, they assert, it is unreasonable to require, as a key to integration, that ''the transmission provider is able to provide transmission service to itself or other transmission customers over those facilities'' because it may be that the facilities are necessary to provide network service to the customer that owns the facilities and a credit would be appropriate. They argue that if transmission facilities serve load included in the network customer's network load, the transmission customer should get a credit.

Blue Ridge states that ''[i]f the Commission does intend to change its standard or otherwise codify the result of *FMPA II*, then Blue Ridge urges rehearing and suggests a more analytical, policy oriented approach to the issue.'' (Blue Ridge at 31). It recommends adding the following language to the end of section 30.9 of the tariff concerning credit for new facilities: ''or if such facilities are integrated with, and support the

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

[269] FERC Stats. & Regs. at 31,742–43; *mimeo* at 316–18.

[270] 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.

Transmission Provider's Transmission system.'' (Blue Ridge at Attachment 1).

FMPA argues that a transmission provider can avoid paying credits for transmission that is functionally the same as that of the transmission provider simply by refusing to jointly plan. It asserts that the Commission should adopt either the Commission's integration test, without requiring joint planning, or a functionality test that considers whether the facilities of the customer and transmission provider are similar. Moreover, it argues that a more inclusive definition of the grid would better achieve comparability and competitive generation markets and would remove incentives to avoid joint planning. It argues that crediting customer-owned transmission also promotes the establishment of regional grids.

Several entities state that the standard as to future network customer-owned facilities should be modified to make joint planning mandatory on the part of the transmission provider, who otherwise has little incentive to cooperate and coordinate.[272] They claim that in joint planning, plans cannot be developed by the transmission provider alone. They further argue that the Commission should not deem the lack of joint planning dispositive of the operation and planning issue.

TAPS asks the Commission to clarify that credits will be provided for existing, as well as future, facilities if the integration requirement is met.

Wisconsin Municipals asks the Commission to clarify that the level of customer-owned credits is a rate issue and that if parties have negotiated provisions for credits, the Final Rule cannot be used by transmission providers to avoid the obligations undertaken in a settlement.

NRECA and TDU Systems assert that the Commission should not abandon its historical practice of rolling in transmission facilities for purposes of transmission pricing; otherwise, the Commission must examine the function of all transmission facilities in a transmission provider's rate base and exclude them if they are not ''integrated'' (referencing Order No. 888 at 317 n.452). They argue that because customers would have to file section 206 filings to enforce this, the Commission should require transmission providers to file under section 205 the identity of those facilities that will be included in the transmission rate base, those that will be excluded, and the supporting data.

Turlock wants the Commission to provide concrete guidelines as to the eligibility of facilities for customer credits. Moreover, Turlock asserts that credits may be appropriate for point-to-point customers as well—especially in Northern California where PG&E, according to Turlock, encouraged customers to build facilities. Turlock finds this particularly important where PG&E has proposed to switch from subfunctionalized ratemaking to system-wide rolled-in ratemaking. It asserts that, if there are system-wide rolled in rates without a credit provision, there may be a violation of the ''or'' pricing policy.

Several entities ask the Commission to clarify that the crediting provision works on a comparable basis for transmission customers and providers.[273] They ask the Commission to clarify that the phrase ''serve all of its power and transmission customers'' in section 30.9 is to be measured by the facilities that the transmission provider rolls into rate base to determine transmission rates and the transmission component of requirements rates. For example, they argue that because AEP rolls radial lines into rate base, comparable customer-owned lines should receive a credit. They also ask the Commission to clarify that the test that facilities are integrated into the planning and operations of the transmission provider is an objective standard that is satisfied by evidence that the transmission provider's load flow studies take into account the transmission customer's facilities. They assert that the standard should not be a subjective one that depends on whether the transmission provider says that it includes customer facilities in its planning and operations.

AMP-Ohio adds that the integration requirement should also be satisfied by evidence that the transmission provider includes costs in its rate base or transmission expenses that are associated with transmission facilities of utilities that it acquires. Michigan Systems also asks that the Commission clarify that the test in section 30.9 is a functional test and not whether the transmission owner says it is integrating its operations.

Michigan Systems states that it has no objection to leaving determinations of credits to rate cases, as an abstract matter, but asserts that the Commission should make clear that it will not implement newly-filed tariffs in a way that imposes multiple or inconsistent charges for transmission in the interim. Otherwise, it asserts, transmission dependent utilities may be out of business if they must wait years to get credit for grid transmission they already own and that they must pay to finance. Michigan Systems also states that it would be illegal to require systems to pay for transmission by applying a load ratio share based on total loads when they have made investments under contracts for transmission to serve a portion of those loads.

TAPS states that the Commission must define what it means by ''integrated.'' TAPS asserts that the term should mean grid facilities used to integrate the network customer's resources and loads. It further asserts that the Commission should continue to use the test whether the facilities serve a comparable function. Unless a proper credit is provided, TAPS maintains, network customers could pay twice for transmission. TAPS adds that without proper crediting, the Commission cannot require load ratio pricing of network service.

TAPS asks the Commission to clarify the method it will use to calculate the credit in individual cases and suggests that the Commission adopt the method TAPS proposed in its initial comments in this proceeding.

With respect to joint ownership of transmission facilities or ownership of transmission facilities through a joint exercise of powers agency (JPA) or a Generation and Transmission Cooperative, TANC asks that the Commission provide for proportionate entitlement to a credit among those who have invested in, and are entitled to the use of, such facilities. TANC also argues that the credit should apply to facilities used to complete a transaction under the transmission provider's point-to-point tariff. Further, TANC asserts that upon a showing that the facilities are integrated, the credit in section 30.9 should be mandatory and asks that the Commission provide guidance as to the method of either calculating or applying the credit.

Commission Conclusion

The Commission reaffirms its finding in Order No. 888 that the question of credits for customer-owned facilities is best resolved on a fact-specific, case-by-case basis.[274] Accordingly, the Commission does not believe that the rehearing requests seeking specific guidance regarding various aspects of

[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.

customer credits are appropriate for resolution at this time.[275]

In order to conform the Final Rule preamble language with the tariff provisions of Order No. 888,[276] we will modify section 30.9 of the pro forma tariff to provide that a customer may receive a credit for its own facilities if it demonstrates that ''its transmission facilities are integrated into the plans or operations (instead of ''planning and operations'') of the transmission provider to serve its power and transmission customers.'' [277] The intent of section 30.9 of the pro forma tariff is that, for a customer to be eligible for a credit, its facilities must not only be integrated with the transmission provider's system, but must also provide additional benefits to the transmission grid in terms of capability and reliability, and be relied upon for the coordinated operation of the grid. Indeed, in the Final Rule we explicitly stated that 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 these facilities.[278]

The Commission further stated in the Final Rule that where disputes over credits for customer-owned facilities arise, it encourages all parties not to seek formal resolution at the Commission, but to first pursue alternative dispute resolution. In this regard, the customer at the time it is requesting network service could also request that a study be undertaken by the company to analyze the impact and benefit of the customer's facilities provided to the integrated transmission network.

We share the concern of APPA and others that transmission providers have not allowed transmission customers to participate in the planning process for new transmission projects. Allowing potential transmission customers the opportunity to participate in transmission projects is important in ensuring that regional transmission needs are met efficiently. One way of accomplishing this goal is through an RTG, ISO, or other regional entity that has an open planning process. Where such entities do not exist, we strongly encourage public utilities to hold an open season for all transmission expansion projects, including those in response to a service request, so that all entities in the region have an opportunity to identify their future needs and participate in the project.

Finally, requests for the Commission to mandate joint-planning are addressed below in the discussion of section 1.12 of the pro forma tariff.

h. Ceiling Rate for Non-firm Point-to-Point Service

In the Final Rule, the Commission stated that it is important to continue to allow pricing flexibility.[279] The Commission explained that, in accordance with its current policies, the rate for non-firm point-to-point transmission service may reflect opportunity costs. The Commission further explained that, 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. On the other hand, the Commission explained that, if a utility chooses not to adopt opportunity cost pricing, the non-firm rate is capped at the firm rate.

Rehearing Requests

Duquesne asks the Commission to clarify that the phrase ''the non-firm rate is capped at the firm rate'' does not mean that the Commission is deviating from its principles that non-firm transmission service must be priced in a manner that (i) reflects the interruptibility of the service, and (ii) is economically efficient.

Commission Conclusion

With regard to Duquesne's request, we clarify that the firm transmission rate simply represents a maximum rate or price cap for non-firm transmission prices. We emphasize that non-firm transmission prices should reflect the interruptibility of the service and should promote efficient use of the transmission system, subject to this price cap. Accordingly, while in some circumstances non-firm transmission rates may be set at the firm transmission rate level, the Commission expects that non-firm transmission rates would, in most instances, be priced below the price cap.

i. Discounts

In the Final Rule, the Commission stated that if a transmission provider offers a rate discount to its affiliate, or if the transmission provider attributes a discounted rate to its own wholesale 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.[280] In addition, the Commission required that discounts from the maximum firm rate for the provider's own wholesale use or its affiliate's wholesale use 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.[281] Finally, the Commission explained that 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.

Rehearing Requests

Utility Position

A number of utilities assert that the affiliate discounting provision is too broad.[282] SoCal Edison asserts that if the affiliate discounting provision is kept, the requirement to discount similarly for non-affiliates on unconstrained paths should be limited to offers on the same day only for new transmission services and only for the duration of the service offered to the affiliate.

Entergy and Southwestern assert that the Commission should change the discount language, which provides that

[275] 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.

[277] 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).

[278] 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.

[281] 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.

whenever the transmission provider offers a discount to an affiliate, or attributes a discount to its own transaction, it must offer a comparable discount to all similarly situated transmission customers. Southwestern believes that the Commission does not justify its different treatment of discounts to affiliates and discounts to non-affiliates—section 205(b) of the FPA states that a public utility may not give any *undue* preference or advantage to any person. Southwestern also notes that for gas pipelines, the Commission required that affiliate discounts be available to similarly situated shippers (citing 18 CFR 161.3(h)(1)).

PacifiCorp suggests replacing the last sentence of section 37.6(c)(3) of the OASIS regulations with the following sentence: ''With respect to any discount offered to its own power customers or its affiliates, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all Transmission Customers on the same transmission path and on all other unconstrained transmission paths parallel thereto for deliveries to the same Point of Delivery.'' It argues that the Commission's approach of requiring the same discount to all transmission customers on the same path and on all unconstrained transmission paths would discourage discounting, even when done to attract counter-wheeling to relieve constraints.[283]

Several utilities argue that the discount language should be changed to require only that the same discount be offered to all customers on the same path.[284] Otherwise, Montana Power asserts, transmission providers will be reluctant to offer discounts to its own marketers so as to protect revenues on other paths.

AEP suggests that the discount language be changed to require that the discount be made available for all unconstrained paths terminating at the same interface.

Illinois Power argues that the Commission should require discounts for equivalent (*i.e.*, similarly situated) service requests, on the basis of location, term and time of service, which it asserts conforms to the Commission's standards for natural gas pipelines (citing 18 CFR 161.3(h)). Otherwise, it asserts, the Commission's approach will result in inefficient use of scarce transmission capacity and thereby discourage efficient bulk power trading.

[283] *See also* Washington Water Power.

[284] *E.g.*, Montana Power, Allegheny, Puget.

VEPCO asserts that transmission providers must be given more flexibility to accommodate differences in regional wholesale markets and to maximize the movement of economical capacity and energy. It states that a transmission provider will provide discounts only if they are not detrimental to existing committed agreements or potential future revenue—revenue from additional sales must offset the decrease in revenues from making discounts. It suggests that preferential treatment can be reduced by the following constraints: (1) offer the same discount to all transmission requests to the same points of delivery for the same time, and (2) a discount should not apply to service already agreed to but not yet provided at that point. Utilities For Improved Transition adds the following constraint: evaluate request for discount on whether it would increase volume without reducing total revenues.[285] Florida Power Corp asserts that because communications regarding discounts must be posted on OASIS, preferential treatment would be readily apparent.

EEI states that the discount requirement has the potential to arbitrarily reduce the revenue that the transmission provider may be able to obtain over alternative paths that may be unconstrained, but of greater potential value than the path(s) identified as appropriate for discounting. It adds that the requirements for posting discounts should be the same regardless of affiliation and should be limited to the specific transmission path(s) discounted by the transmission provider.

Carolina P&L argues that the Commission should permit selective discounting of non-firm transmission service on a posted-in-advance (on OASIS) basis that will not create a most favored nations situation merely because the transmission provider or an affiliate availed itself of the posted discount.

Customer Position

Tallahassee asks the Commission to clarify that the transmission provider must automatically apply the discount to any eligible customer or, at the minimum, provide actual and timely notice of the discount's availability.

Similarly, PA Coops asserts that ''[i]f transmission service is being discounted to any customer, affiliated or not, for a specific level of service at a specific point in time, it should be equally discounted to all customers receiving the same transmission service. To do otherwise is unduly discriminatory.'' (PA Coops at 11).

[285] *See also* Florida Power Corp.

TAPS asserts that all discounts must be posted in advance, the reasons for the discounts should be transparent, the transmission provider should keep all requests for discounts in a log, and short-lived discounts should not be permitted.

Commission Conclusion

In response to the arguments raised with respect to discounting, we will revise our policy on discounting transmission service. This revised policy will assure consistency with our standards of conduct requirements, which preclude a utility's wholesale merchant function from having access to its transmission system information (including price) not posted on the OASIS that is not otherwise also available to the general public or that is not also publicly available to all transmission users. The revised policy also should result in less opportunity for affiliate abuse and enable better monitoring of potential abuse. Additionally, we have concluded that the same policy should apply regardless of whether the discount is for the transmission provider's own wholesale use (*i.e.*, wholesale merchant function), for the transmission provider's affiliate, or for a non-affiliate.

A transmission provider should discount only if necessary to increase throughput on its system. While the potential for abuse is most obvious in situations involving the transmission provider's own wholesale use or use by an affiliate (own use/affiliate),[286] we must also be concerned with a transmission provider agreeing to discount to non-affiliates in any unduly discriminatory manner. To satisfy these dual concerns, we believe that any ''negotiation'' [287] between a transmission provider and potential transmission customers should take place on the OASIS. Toward this end, we believe three principal requirements are appropriate. (These requirements would remain even after negotiation takes place on the OASIS.)

First, any offer of a discount for transmission services made by the transmission provider must be announced to all potential customers solely by posting on the OASIS. This requirement, which will ensure that all potential transmission customers under

[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.

[287] ''Negotiation'' would only take place if the transmission provider or potential customer seeks prices below the ceiling prices set forth in the tariff.

the pro forma tariff will have equal access to discount information, will guard against own use/affiliate customers gaining an unfair timing advantage concerning the availability of discounts.

Second, we will require that any customer-initiated requests for discounts occur solely by posting on the OASIS, regardless of whether the customer is an own use/affiliate or a non-affiliate. We have considered, and rejected at least for now, a more restrictive approach which would require that all discounts be initiated solely through offers by the transmission provider. Under such an arrangement, negotiations for discounts would effectively take place by customers accepting or not accepting the offered discount. While such an arrangement could better protect against affiliate abuse, it might be less efficient.[288] Accordingly, we will permit customer-initiated requests for discounts but will require that such requests be visible (via posting on the OASIS) to all market participants.

Finally, we will require that, once the transmission provider and customer agree to a discounted transaction, the details (*e.g.*, price, points of receipt and delivery, and length of service) be immediately posted on the OASIS. This requirement will be equally applicable regardless of whether the customer is an own use/affiliate or non-affiliate.

We will also revise our policy with respect to the transmission paths on which a discount must be offered. Many petitioners argue that the policy in Order No. 888, particularly that the discount rate must be offered over all unconstrained paths, is too broad, and may provide disincentives for the efficient operation of the transmission grid. Their concerns include, for example, the possibility that the policy would inhibit the transmission provider from offering discounts that would relieve line constraints. For example, PacifiCorp argues that it would be reluctant to offer a discount on northbound power flows that would relieve transmission constraints on transmission paths that are normally used for southbound flows, if by virtue of discounting northbound flows, it would also be required to discount all unconstrained southbound flows. Another concern is that while requiring discounts on all unconstrained paths could conceivably result in more service being provided, it may not have that effect. Since the level of transmission revenues will decline if the discount applies to all unconstrained paths and this, in turn, could reduce the credit to firm transmission users for non-firm service revenues, transmission providers may simply decide not to discount a particular unconstrained path. In light of these persuasive arguments, we will no longer require the transmission provider to provide the same discount over all unconstrained paths.

Under our revised policy, if the transmission provider offers a discount on a particular path, *i.e.*, from a point of receipt to a point of delivery, the transmission provider must offer the same discount for the same time period on all unconstrained paths that go to the same point(s) of delivery on the transmission provider's system. In this regard, a point of delivery includes an interconnection with another control area. Also, if a power purchaser can take delivery at more than one point of delivery (such as two substations serving a municipality), we would consider these to be the same point of delivery for discounting purposes.

This change provides some flexibility to transmission providers to set prices for transmission service efficiently and at the same time maintains the requirement that public utilities provide comparable service at rates that are not unduly discriminatory or preferential. The change is designed to ensure that the transmission owner will provide the same discounted service to its competitors that it provides to itself or its affiliates for their wholesale sales.

The Commission considered requiring the transmission provider offering a discount on a particular path to offer discounts on all unconstrained paths that go from the same points of receipt on the transmission provider's system and decided that such a requirement was not necessary to ensure comparability.

We further clarify that a transmission provider may limit its offers of discounts over the OASIS to particular time periods. There is nothing *per se* unduly discriminatory in offering a discount in one period and not in another.[289]

Finally, we recognize that even with this revised policy utilities may engage in affiliate abuse by offering discounts only at times or along paths that are of advantage to it or its affiliates. While requiring the posting of discount information on the OASIS does not completely eliminate the possibility of affiliate abuse, these procedures will allow ready identification of unduly discriminatory or preferential transactions, and thus make easier the preparation of complaints that the transmission provider is engaging in a pattern of discounting that indicates affiliate abuse, such as offering discounts preferentially at times or on paths that only the transmission provider or its affiliate can take advantage of, without offering discounts at times or on paths that its competitors can take advantage of.

We will require that all ''negotiation'' take place on the OASIS as soon as practicable, as explained in Order No. 889–A.

j. Other Pricing Related Issues Not Specifically Addressed in the Final Rule

(1) Demand Charge Credits

Rehearing Requests

VT DPS argues that demand charge credits for curtailments or interruptions are needed to provide an incentive to utilities to provide high quality service. It points out that the Commission has allowed demand charge credits in the gas pipeline context (citing *Tennessee Gas Pipeline Co.*, 71 FERC ¶ 61,399 at 62,580).[290]

Commission Conclusion

The Commission does not believe that electrical systems will be less reliable as a result of our initiatives on competition and open access in the Final Rule. As such, the Commission does not intend to require demand charge credits on a generic basis to encourage reliable transmission service. However, because the Commission has not mandated any particular rate design methodology under the Final Rule pro forma tariff, customers are free to argue in the compliance filing proceedings or subsequent section 205 proceedings that demand charge credits are reasonable in the context of a particular rate design method.

(2) In-Kind Transactions

Rehearing Requests

CCEM asserts that in-kind transactions in reformed power pool agreements should be abolished because of the uncertainty of valuing non-cash transactions and the potential for cross subsidizing the utilities' generation sales. It contends that a cash equivalent transaction for all formerly in-kind transactions among transmission owners is needed.

[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.

Commission Conclusion

To satisfy CCEM's concerns, the Commission concludes that in-kind transactions must be provided on a non-discriminatory basis. The Commission recently found that in-kind transactions (*i.e.*, transactions with payment by energy returned in kind instead of by a monetary charge) with no unbundling requirement ''could hide and, thereby, mask unduly preferential terms and rates,'' which is precisely one of the practices that the Final Rule is intended to remedy.[291] While we will now require that all in-kind transactions be provided on an unbundled basis, we stress that we are not prohibiting in-kind transactions. Utilities are free to enter into contracts that contain in-kind compensation for the wholesale generation component, as long as it unbundles such transactions. Consistent with *Arizona*, unless the other party to the transaction contracts for transmission service under that utility's open access pro forma tariff, that utility must obtain the necessary transmission and ancillary services under the terms of its open access transmission tariff and must separately state the transmission and ancillary service prices that it will recover from the customer.

2. Priority For Obtaining Service

a. Reservation Priority for Existing Firm Service Customers

In the Final Rule, the Commission indicated that a transmission provider may reserve in its calculation of ATC transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon.[292]

Rehearing Requests

This issue is discussed in Section IV.C.5. (Reservation of Transmission Capacity for Future Use by Utility).

b. Reservation Priority for Firm Point-to-Point and Network Service

In the Final Rule, in response to concerns that network service should have a reservation priority over point-to-point service because of pricing differences, the Commission allowed utilities the opportunity to eliminate the differences in pricing between network and point-to-point services by permitting utilities to adopt point-to-point reservations as the customer load.[293] The Commission explained that utilities are free to propose a single cost allocation method for the two services.

In addition, the Commission provided that reservations for short-term firm point-to-point service (less than one year) will be conditional until one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. According to the Commission, these conditional reservations may be displaced by competing requests for longer-term firm point-to-point service. The Commission explained that after the deadline, the reservation becomes unconditional, and the service would be entitled to the same priorities as any long-term point-to-point or network firm service.

Moreover, the Commission explained that the Final Rule pro forma tariff does not propose point-to-point or network service with various degrees of firmness beyond the simple categories of firm and non-firm. It explained that when a customer requests firm transmission service, reservation priorities are established based first on availability, and in the event the system is constrained, based on duration of the underlying firm service request—customers may choose the ''firmness'' of service they want by electing to take non-firm service, or by reserving and paying for firm service.

Rehearing Requests

NRECA and TDU Systems declare that provisions making reservations for short-term firm point-to-point service conditional will not reduce the incentive to cream skim, *i.e.*, a customer has an incentive to submit reservations for very short terms without fear of not getting service because it can always increase its request to match another longer request. They suggest an alternative: all native load, network, and long-term firm (one year or more) requests would be given priority over short-term firm requests, which would have priority over non-firm requests.

Commission Conclusion

The Final Rule has sufficiently minimized the potential for cream skimming. Further, we note that the alternative proposed by NRECA & TDU Systems has substantially been adopted in Order No. 888. Specifically, Order No. 888 provides: (1) public utilities the right to reserve existing transmission capacity needed for native load growth and network transmission customer load growth,[294] and (2) existing transmission customers the right of first refusal.[295] The only entities not covered above—potential long-term firm customers—must submit their service applications as far in advance as practicable.

c. Reservation Priorities for Non-firm Service

In the Final Rule, the Commission found that network economy purchases should have a reservation priority over non-firm point-to-point and secondary point-to-point uses of the transmission system.[296]

Rehearing Requests

North Jersey argues that non-firm service should be allocated on a first-come, first-served basis, and where multiple customers request service at the same time, available capacity should be allocated on a pro rata basis. It asserts that the proposed priority system based on duration of non-firm service would simply encourage non-firm customers to request service for longer durations than needed.

Commission Conclusion

We reject North Jersey's argument that the proposed priority system based on duration of non-firm service would encourage non-firm customers to request service for longer durations than needed. North Jersey ignores the fact that section 14.2 of the pro forma tariff establishes a right for eligible customers with existing non-firm reservations to match any longer term reservation before being preempted.

A related matter is discussed in Section IV.G.3.b below.

3. Curtailment and Interruption Provisions[297]

a. Pro-Rata Curtailment Provisions

In the Final Rule, the Commission found that curtailment on a pro-rata basis is appropriate for curtailing transactions that substantially relieve a

[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.

[295] 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.

constraint.[298] The Commission explicitly allowed the transmission provider discretion to curtail the services, whether firm or non-firm, that substantially relieve the constraint.

The Commission also indicated that it would consider granting deference to an alternative curtailment method to avoid hydro spill if such a regional practice is generally accepted and adhered to across the region.

The Commission further found that under network and point-to-point service, the transmission provider may propose a rate treatment (penalty provision) to apply in the event a customer fails to curtail service as required under the Final Rule pro forma tariff and indicated that such proposals will be evaluated on a case-by-case basis on compliance.

Rehearing Requests

PA Com asserts that pro rata curtailment fails to hold native load harmless to the extent practical as required by the FPA. PA Com points out that on January 19, 1994, PJM initiated pro-rata load shedding, in part to preserve economic transactions, leaving customers in Pennsylvania without power during a record cold spell.

VA Com argues that pro rata curtailment may harm native load customers and section 206 complaints are after the fact and of little assistance to native load. VA Com argues that curtailment priority (in order of curtailment) should be: non-firm, contract firm, and then native load, and that utilities should have flexibility to curtail on a pro-rata basis within classes, subject to state curtailment policy.

Several entities argue that provision must be made for preference in curtailment priorities obtained through settlement, through payment of good and valuable consideration, or under existing transmission contracts.[299] Turlock argues that customers should be able to obtain a variation from the pro rata scheme if they can show that they have made either past or future investments to improve constrained facilities and that the quid pro quo for their investment is improved curtailment priority.

Allegheny asks the Commission to clarify that it did not intend to require public utilities to shed (through pro rata curtailment) native transmission load customers in order to preserve some portion of service to through system users of the grid. According to Allegheny, the FPA mandates that service reliability to franchise customers must be maintained and through-system users are not similarly situated to native transmission load customers and should not be treated the same in an emergency because through system customers can protect themselves, but native transmission load customers cannot. Allegheny adds that failure to maintain system reliability would violate section 211 of the FPA.

CCEM asserts that hard and fast priority rules are needed to prevent inconsistent rules from developing for different utilities, pools, or control areas.

Commission Conclusion

Assertions that the pro-rata curtailment provision in the tariff may harm native load customers are misplaced. The Commission clarified in the Final Rule that it was not requiring a pro-rata curtailment of *all* transactions at the time of a constraint, but rather curtailment of those transactions, whether firm or non-firm, that effectively relieve the constraint.[300] The Commission also required that such curtailments be made on a non-discriminatory basis, including the transmission provider's own wholesale use of the system. The Commission further explained that the pro-rata curtailment provision was intended to apply to situations where multiple transactions could be curtailed to relieve a constraint. Of course, if curtailment of multiple transactions is necessary, non-firm service would be curtailed prior to firm service. However, the Commission established that, in emergencies, the transmission provider had the discretion to interrupt firm service under the tariff to ensure the reliability of its transmission system.

In terms of reliability, we believe that sufficient safeguards have been established to protect native load. In particular, the transmission provider is responsible for planning and maintaining sufficient transmission capacity to safely and reliably serve its native load. Order Nos. 888 and 889 permit the transmission provider to reserve, in its calculation of ATC, sufficient capacity to serve native load.

Allegations that a utility did not curtail on a non-discriminatory basis, but instead favored a certain class of customer or type of transaction should be filed in a section 206 complaint proceeding to be reviewed on a case-specific basis. While it is true that such complaints will be processed on an after-the-fact basis, it is only on a fact-specific basis that such complaints can be fully and adequately reviewed.

Additionally, tariff section 14.7 does in fact establish that for curtailment purposes, non-firm point-to-point transmission shall be subordinate to firm transmission service and non-firm service may also be interrupted for economic reasons. However, adopting curtailment schemes based solely on classes of service, as proposed by the VA Com, is inappropriate. Specifically, VA Com's proposal to curtail all non-firm transmission transactions prior to firm transactions could exacerbate an emergency situation. For example, a curtailment could be necessary due to a constraint affecting northbound transactions. However, curtailing all non-firm transactions, including southbound transactions (or counterflows), could worsen the situation. Accordingly, the Commission believes the approach established in the Final Rule of allowing non-discriminatory curtailments of the transaction(s) that effectively relieve(s) the constraint is appropriate.

In response to CCEM's concerns regarding the potential for inconsistent rules for different utilities, pools or control areas, the Commission explained in the Final Rule that any proposed deviations from the non-price terms and conditions of the pro forma tariff, such as regional practices, must be adequately supported by the utility proposing the change.

Finally, Order No. 888 did not abrogate existing contracts;[301] therefore, customers with unique curtailment priorities established by pre-existing contracts would not have these priorities eliminated for the term of the existing contract.

b. Curtailment and Interruption Provisions for Non-firm Service

In the Final Rule, the Commission explained that it had clarified in the pro forma tariff that a network customer's economy purchases have a higher priority than non-firm point-to-point transmission service (citing *AES Power, Inc.*[302]).[303]

The Commission also revised the pro forma tariff to allow the transmission provider to curtail non-firm service for reliability reasons or to interrupt the service for economic reasons (*i.e.,* in order to accommodate (1) a request for

[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).

[303] FERC Stats. & Regs. at 31,750; *mimeo* at 338–39.

firm transmission service, (2) a request for non-firm service of greater duration, (3) a request for non-firm transmission service of equal duration with a higher price, or (4) transmission service for economy purchases by network customers from non-designated resources). The Commission further explained that a firm point-to-point customer's use of transmission service at secondary points of receipt and delivery will continue to have the lowest priority.

Rehearing Requests

For comparability, CCEM asserts that secondary receipt points should be made subordinate to other firm services,[304] but should have priority over non-firm point-to-point transactions. CCEM also argues that non-firm point-to-point service, once scheduled, should not be interrupted to accommodate non-firm service for a network service economy purchase.

VT DPS argues that firm flexible point-to-point service over secondary points of receipt and delivery should have a priority over non-firm point-to-point service (citing sections 14.2 and 14.7 of the pro forma tariff). It argues that this priority is necessary to reflect the fact that point-to-point customers pay for firm service and to be consistent with the treatment of network customers. VT DPS notes that in the natural gas industry the Commission has found that such priority is essential to reflect the fact that firm customers are paying for firm service (citing Order No. 636–B).

APPA asks the Commission to clarify the conditions under which the Commission will allow non-firm service to be interrupted by the transmission provider solely for economic reasons. APPA claims that this clarification is needed so as to prevent interruption of service on a discriminatory basis.

CCEM states that non-firm point-to-point transmission service does not provide the user with a specific capacity reservation, and therefore such service should bear no reservation or demand-like charges and the customer should pay a commodity-only charge only for when the service is being provided.[305] It contends, for example, that if a customer schedules one week of weekly non-firm transmission service and is interrupted on the second day of service, the customer should only pay for the service it used and should have no responsibility to take or to pay for service for the remainder of the week. Alternatively, it argues that if there are reservation charges and the non-firm customer pays for service on a ''take-or pay basis'' regardless of use, non-firm service should not be subject to being bumped once service is scheduled and power is flowing. Moreover, if the non-firm point-to-point transmission customer does pay reservation charges on a ''take-or-pay basis,'' the non-firm reserved capacity should be tradeable in a secondary market.

Commission Conclusion

We reject CCEM's proposal to prevent scheduled non-firm transmission service from being interrupted to accommodate economy purchases for network customers. Non-firm service is provided on an interruptible basis. To the extent CCEM wishes to obtain service that cannot be interrupted to accommodate other transactions, it has the option of requesting firm service in the form of either network or point-to-point transmission service.

APPA's concerns have already been addressed by the Commission. In the Final Rule, the Commission specifically listed the economic reasons that a transmission provider could interrupt non-firm point-to-point transmission to include:

> accommodat[ing] (1) a request for firm transmission service, (2) a request for non-firm service of greater duration, (3) a request for non-firm transmission service of equal duration with a higher price, or (4) transmission service for economy purchases by network customers from non-designated resources.[306]

CCEM's arguments are misplaced in that they focus on the specific rate (including any potential credits for service interruption) that utilities may propose for non-firm point-to-point transmission service. Order No. 888 did not mandate any pricing methodology to be used for non-firm point-to-point transmission service. Rather, the Commission established the minimum non-price terms and conditions necessary to ensure comparable service. As the Commission explained in the Final Rule, utilities are free to propose any rates for non-firm point-to-point transmission in a section 205 filing consistent with the Commission's Transmission Pricing Policy Statement.[307] However, the Commission will evaluate the appropriateness of such proposed rates against the non-price terms and conditions established in the pro forma tariff or other non-price terms and conditions proposed and fully supported by the utility.[308]

The Commission has previously addressed VT DPS' point.[309] Non-firm point-to-point customers pay for non-firm service as their service. Firm point-to-point customers, on the other hand, contract and reserve a specified amount of service over designated points of receipt and delivery. The Commission permitted these firm point-to-point customers to use secondary non-firm service (from points of receipt/delivery other than those designated in their service agreement) on an as-available basis at no additional charge. Because the firm point-to-point customers taking secondary non-firm are accorded this scheduling flexibility at no additional charge, they are properly accorded a lower priority than stand alone, non-firm transmission. In contrast, network customers are responsible for paying for a percentage of total system transmission costs in order to serve their designated network loads whether the energy is from designated network resources or from non-designated resources on an as-available basis.[310] Because the network customer pays a load-ratio share of total transmission costs, it receives a higher priority. Significantly, if any firm point-to-point customer wants to avail itself of the higher priority associated with economy energy purchases under the network tariff, it is free to do so by undertaking the cost responsibilities associated with network service.

Finally, in response to VT DPS, we note that we have chosen different approaches in the electric and natural gas areas. In this regard, we recognize that there is a trade-off between encouraging tradable capacity rights versus maximizing revenues that can be credited against the transmission provider's costs of providing transmission service. On the electric side, fully developed transmission capacity trading rights simply do not exist at this time, and so we have chosen to emphasize an approach that maximizes revenues to be credited to transmission customers. However, we will continue to evaluate our approach in the context of any future transmission rate proposal that is based on the concept of tradable capacity rights.

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[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.

[308] 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).

[310] This is comparable to the service a utility provides its native load.

4. Reciprocity Provision

In the Final Rule, the Commission concluded that it was appropriate to require a reciprocity provision in the pro forma tariff.[311] The Commission explained that this provision will be applicable to all customers, including non-public utility entities such as municipally-owned entities and RUS cooperatives, that own, control or operate interstate transmission facilities and that take service under the open access tariff, and any affiliates of the customer that own, control or operate interstate transmission facilities.

The Commission developed a voluntary safe harbor procedure under which non-public utilities would be allowed to submit to the Commission a transmission tariff and a request for declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. The Commission explained that if it finds that a tariff contains terms and conditions that substantially conform or are superior to those in the Final Rule pro forma tariff, it will deem it an acceptable reciprocity tariff and require public utilities to provide open access service to that non-public utility.

If a non-public utility chooses not to seek a Commission determination that its tariff meets the Commission's comparability standards, the Commission declared that a public utility could refuse to provide open access transmission service. However, any such denial must be based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements.

In support of its decision to adopt a reciprocity provision, the Commission explained that it was not requiring non-public utilities to provide transmission access, but was conditioning the use of public utilities' open access services on an agreement to offer open access services in return. The Commission noted that non-public utilities can choose not to take service under public utility open access tariffs and can instead seek voluntary service from the public utility on a bilateral basis.

The Commission further explained that the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the non-public utility seeks to take advantage of open access on a public utility's system. However, the Commission recognized that Congress has determined that certain entities in the bulk power market can use tax-exempt financing by issuing bonds that do not constitute ''private activity bonds'' [312] or by financing facilities with ''local furnishing'' bonds.[313] The Commission stated that it was not its purpose to disturb Congress' and the IRS's determinations with respect to tax-exempt financing. Therefore, the Commission clarified that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities.[314]

With respect to local furnishing bonds, which are available to a handful of public utilities, the Commission noted that Congress, in section 1919 of the Energy Policy Act, amended section 142(f) of the Internal Revenue Code to provide that a facility shall not be treated as failing to meet the local furnishing requirement by reason of transmission services ordered by the Commission under section 211 of the FPA if ''the portion of the cost of the facility financed with tax-exempt bonds is not greater than the portion of the cost of the facility which is allocable to the local furnishing of electric energy.'' [315] So that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime, the Commission required any public utility that is subject to the Open Access Rule that has financed transmission facilities with local furnishing bonds to include in its tariff a similar provision that it will not contest the issuance of an order under section 211 of the FPA requiring the provision of such service, and will, within 10 days of receiving a written request by the applicant, file with the Commission a written waiver of its rights to a request for reciprocal service from the applicant under section 213(a) of the FPA and to the issuance of a proposed order under section 212(c).

In addition, the Commission limited the reciprocity requirement to the applicant and corporate affiliates. The Commission explained that if a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, would be required to offer transmission service. However, if a member distribution cooperative itself receives transmission service from the transmission provider, then it (but not its G&T cooperative) must offer reciprocal transmission service over any interstate transmission facilities that it may own, control or operate.

Furthermore, the Commission explained that a non-public utility, for good cause shown, may file a request for waiver of all or part of the reciprocity requirement.

The Commission also explained that the reciprocity requirement will apply to any entity that owns, controls or operates interstate transmission facilities that uses a marketer or other intermediary to obtain access. The Commission added that it would apply the same criteria to waive the reciprocity condition for small non-public utilities as for small public utilities.

Rehearing Requests

Reciprocity Provision—Public Power Position

A number of public power entities argue that the reciprocity provision should be eliminated because the Commission cannot require indirectly what it cannot require directly.[316] Several other public power entities add that the reciprocity obligation is beyond the jurisdiction of the Commission because the transmission obligations of non-public utilities (*e.g.*, municipal utilities) are established and limited to those required by sections 211 and 212 of the FPA.[317] Tallahassee asserts that the Commission's conditioning approach has the effect of excluding an entire class of transmission customer from open access, *i.e.*, those unable to grant reciprocal service. This, Tallahassee asserts, is discriminatory and contrary to the purpose of the Final Rule and the requirements of sections 205, 206 and 212 of the FPA. TANC argues that the Commission does not have the discretion to grant or withhold open access transmission on the condition that the customer consent to doing something that the Commission admits it cannot directly order: ''The Commission has never 'conditioned' its duty to allow only just and reasonable rates on any action by the customer.'' (TANC at 16).

A number of entities challenge the Commission's assertion that the reciprocity requirement for non-public

[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.

[313] *See* 26 U.S.C. § 142.

[314] 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.

[317] *E.g.*, Redding, Tallahassee, TANC, Dairyland.

utilities is voluntary.[318] Dairyland contends that the alternative of seeking a bilateral agreement is illusory—even if it could be obtained—because Order No. 888 provides that any bilateral wholesale coordination agreement executed after July 9, 1996 will be subject to open access requirements. Dairyland argues that the phrase ''subject to open access requirements'' presumably would include the reciprocity requirement for non-public utilities.

AEC & SMEPA assert that there is no record support for the contention that non-public utilities are responsible for closed systems or that such systems, if any, have an impact on the market.

NRECA asserts that if the reciprocity provision is retained, the Commission should ''modify its terms to incorporate the statutory standards and protections which FPA sections 211 and 212 contain.'' [319]

Umatilla Coop asks the Commission to clarify that distribution cooperatives will not become subject to the reciprocity requirements merely because they purchase power from affiliated cooperatives that are acting as power marketers. TDU Systems assert that a cooperative should not have to render reciprocal service if it would interfere with its ability to obtain RUS loan financing.

TAPS declares that the transmission provider alone should not have access to third-party systems through reciprocity. It maintains that the utility's long-term transmission customers should also be afforded access to those third-party systems so that the transmission provider does not have a competitive advantage. TAPS argues that a third-party should be required to have an open access tariff available.

Reciprocity Provision—Utility Position

A number of utilities argue that the exemption from reciprocity for distribution cooperatives should be eliminated.[320] EEI and Montana-Dakota Utilities assert that G&Ts could eliminate their reciprocity obligation by selling or transferring their transmission facilities to their distribution owner/members. Southwestern argues that the exception for distribution cooperatives puts public utilities at a competitive disadvantage in that distribution cooperatives can use a public utility's system to compete with the public utility, but a public utility cannot use the distribution cooperatives' systems to compete to sell power to their customers.[321] It adds that the exception allows distribution cooperatives to hide behind shell G&Ts. For example, Southwestern argues that Golden Spread Electric Cooperative is a shell G&T because it owns only small amounts of facilities. It concludes that reciprocal access may become especially important if a state implements a retail access plan because section 211 cannot be used to obtain transmission for retail access over a distribution cooperative's system.

Southern claims that cooperatives have argued in courts and in Congress that a G&T cooperative and its distribution cooperative owners are unified economic interests in which the interest of the whole is equal to the sum of the parts, and that federal courts have upheld this view (citing one case—City of Morgan City v. South Louisiana Electric Cooperative Ass'n, 49 F.3d 1074 (5th Cir. 1995) (*Morgan City*)).

EEI claims that clarification of certain aspects of reciprocity is needed: (1) public utilities may not be able to determine if reciprocal service is comparable because non-public utilities do not have to provide Form 1 data, and thus non-public utilities should be required to submit additional data; (2) non-public utilities should be required to functionally unbundle, charge rates to themselves and others that reflect the cost of using the system themselves, comply with the standards of conduct, and establish an OASIS; (3) non-public utility members of an RTG should be required to offer reciprocal service comparable to that provided by public utility members; and (4) a non-public utility should be required to provide all services it is reasonably capable of providing. Carolina P&L adds that a customer should be required to provide the full panoply of transmission services that it is capable of providing because the customer has a right to take any type of service from the transmission provider even though it may only choose one particular service.

Tucson Power asks the Commission to clarify how it will determine the comparability of a non-public utility's tariff. It asserts that first, under the safe harbor option, the Commission should clarify (1) that non-public utilities must comply with the Commission's rules of practice and procedure, and (2) how it will determine that the rates, terms and conditions of the reciprocal service are comparable to the service the non-public utility provides itself (Tucson Power argues that this could require submittal of data comparable to that contained in Form 1). Second, the Commission should eliminate the option that would require the public utility to determine whether the request by the non-public utility is consistent with the tariff. Finally, under the RTG option, the Commission should clarify that the evidentiary requirements for non-public utilities that are members of an RTG will be the same as for non-public utilities using the safe harbor procedure, *i.e.*, any disputes regarding compliance should be resolved by the Commission, not the RTG.

A number of utilities assert that the Commission should not limit the right to obtain reciprocity only to the public utility that provides the transmission service because power could actually flow over other public utilities' transmission lines. They argue that the Commission should ensure that open access transmission is as widely available as possible.[322] EEI asserts that Federal power marketing agencies, including BPA, should be required to provide comparable open access transmission.

Oklahoma G&E argues that Order No. 888 violates the Constitution's equal protection principles because it does not require universal open access. It asserts that the Commission has created an arbitrary distinction between classes of utilities that is unrelated to the Commission's objective and therefore is constitutionally invalid. Oklahoma G&E contends that the proper approach is to proceed under EPAct for all transmitting utilities on a case-by-case basis.

Detroit Edison asks the Commission to clarify that the supplier and the recipient of power are direct beneficiaries and must be considered transmission customers for reciprocity purposes. Otherwise, Detroit Edison contends, parties from jurisdictional transmission transactions may be able to evade reciprocity.

Reciprocity Provision—Other Arguments

CCEM argues that reciprocity should be expanded to require a transmission customer obtaining open access service also to provide open-access transmission service to all eligible customers. Otherwise, CCEM maintains, transmission owners will be able to penetrate into wholesale markets controlled by non-public utilities, but power marketers will not.

[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.

[321] *See also* Oklahoma E&G.

[322] *E.g.,* Montana-Dakota Utilities, Southern, EEI.

CCEM asks the Commission to clarify that when a non-public utility obtains open access from a power pool, member of a power pool, or parties to some form of bilateral coordination agreement, its reciprocity obligation extends to all eligible customers, including all members of the pool or parties to the agreement.

Commission Conclusion

We continue to believe that it is appropriate to condition the use of public utility open access tariffs on the agreement of the tariff user to provide reciprocal access to the transmission provider. No eligible customer, including a non-public utility, that takes advantage of non-discriminatory open access transmission tariff services should be allowed to deny service or otherwise discriminate against the open access provider. As we explained in the Final Rule,

> [n]on-public utilities, whether they are selling power from their own generation facilities or reselling purchased power, have the ability to foreclose their customers' access to alternative power sources, and to take advantage of new markets in the traditional service territories of other utilities. While we do not take issue with the rights these non-public utilities may have under other laws, we will not permit them open access to jurisdictional transmission without offering comparable service in return. We believe the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the non-public utility seeks to take advantage of open access on a public utility's system.[323]

Contrary to arguments raised on rehearing, we are not *requiring* non-public utilities to provide transmission access. Instead, we are conditioning the use of public utility open access tariffs, by all customers including non-public utilities, on an agreement to offer comparable (not unduly discriminatory) services in return.[324] It would not be in the public interest to allow a non-public utility to take non-discriminatory transmission service from a public utility at the same time it refuses to provide comparable service to the public utility. This would restrict the operation of robust competitive markets and would harm the very ratepayers that Congress has charged us to protect. Very simply, we refuse to take a head-in-the-sand approach and order a remedy for undue discrimination that will permit the beneficiaries of the remedy to engage in unduly discriminatory actions.

Moreover, non-public utilities are free to seek from a public utility a waiver of the open access tariff reciprocity condition. We note that this is a modification of our statements in Order No. 888, in which we said that non-public utilities could seek a voluntary offer of transmission service from a public utility on a bilateral basis. Since the time Order No. 888 issued, we have concluded that except in unusual circumstances, public utility services should be provided pursuant to the open access tariff and not pursuant to separate bilateral agreements.[325] This applies to all customers, including non-public utilities. Therefore, rather than requesting a bilateral agreement in order to avoid the reciprocity condition, non-public utilities instead may ask a utility for a waiver of the reciprocity condition in the utility's open access tariff. We disagree with Dairyland that this type of alternative approach is illusory. If the public utility chooses voluntarily to grant a waiver, the reciprocity condition would not apply.

We reject NRECA's request that we incorporate in the reciprocity condition the statutory standards and protections of FPA sections 211 and 212. NRECA states on rehearing that mandated services to third parties would endanger cooperatives' ability to provide service to members, or increase members' costs. It further states that sections 211 and 212 provide substantive protections to ensure continued service to the transmitting utility's own customers, and to avoid their subsidization of services to third parties. NRECA appears to believe that these substantive protections are not provided outside the context of sections 211 and 212. We disagree. We believe the protections that NRECA is seeking are contained in the pro forma tariff and, as required by section 6 of the tariff, the non-public utility must offer its service on similar terms and conditions.[326]

We also reject requests that we not grant the exception to reciprocity provided in the Final Rule for distribution cooperatives and joint action agencies. We continue to believe that if a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, should be required to offer transmission service.[327] Without a corporate affiliation between G&T cooperatives and their member distribution cooperatives, we do not believe it is appropriate to apply the reciprocity condition to the member distribution cooperatives. To do so would result in the member distribution cooperatives being bound by their G&T cooperatives.[328]

Carolina P&L has brought to our attention a possible misunderstanding as to the meaning of comparable transmission service that a non-public utility must agree to provide as a condition of using an open access tariff. Because a non-public utility may choose any type of service from a public utility transmission provider that the transmission provider provides or is capable of providing, we clarify that a non-public utility seeking to take service under the transmission provider's open access tariff must likewise agree to offer to provide the transmission provider any service that the non-public utility provides or is capable of providing on its system in order to satisfy reciprocity. We note that in the Final Rule we explained that ''[a]ny public utility that offers non-discriminatory open access transmission for the benefit of customers should be able to obtain the same non-discriminatory access in return.'' [329] In this regard, because a public utility must have an OASIS and a standard of conduct for employee separation, so must a non-public utility that seeks open access transmission from a public utility.[330]

[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.

[328] 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.

[330] *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

At the same time, however, we deny requests to expand the reciprocity condition.[331] Although we believe that non-public utilities should provide open access transmission as a matter of policy, to require non-public utilities to offer transmission service to entities other than the public utility transmission providers increases the chances that they could lose tax-exempt status. Accordingly, we have adopted a policy that recognizes the statutory tax restrictions placed on non-public utilities but also balances the fundamental unfairness of requiring a utility to make its facilities available to someone who could use that access to the competitive disadvantage of the utility. Ultimately the public interest is best served by nationwide open access and, if the tax issue is favorably resolved, we may revisit the matter.

Moreover, in response to Detroit Edison, we take this opportunity to clarify that reciprocity would apply to a wholesale purchaser if a generation seller obtains transmission service from a public utility to sell to such purchaser and such purchaser owns, operates or controls interstate transmission facilities. The same would be true where the seller owns, operates and controls interstate transmission facilities and the buyer arranges for the transmission service. Just as with marketers or other intermediaries, we do not intend to allow reciprocity to be defeated simply on the basis of whether the seller or buyer requests transmission. Such a result would elevate form over substance.

With respect to TDU System's assertion that reciprocal service should not have to be rendered if it would interfere with RUS loan financing, we note that we have already indicated that reciprocal service need not be provided if tax-exempt status would be jeopardized. If TDU Systems is arguing that we should not require reciprocal service if RUS attaches such a condition in its regulation of RUS-financed cooperatives, we reject such an argument. Such cooperatives have the option to seek bilateral service agreements.

We reject EEI's and Tucson Power's argument that non-public utilities must provide Form 1 data in order to provide comparable service. The Form 1 data would be relevant only if the Commission were setting non-public utilities' rates. Such a detailed review is not necessary, however. *See Santee Cooper*, 75 FERC ¶ 61,209 (1996). Similarly, there is no need to have non-public utilities follow our Rules of Practice and Procedure to satisfy reciprocity.

evaluated under the same criteria applicable to a waiver requests by a public utility.

[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.

Rehearing Requests

Safe Harbor/Waiver Provisions

NRECA states that the following issues related to safe harbor status and declaratory order requests need clarification: (1) under what statutory authority is the Commission considering such petitions? (2) what rights do non-public utilities have to obtain review of Commission determinations with which they disagree? (3) how closely will a reciprocal tariff have to conform to Order No. 888 to win approval? (4) will non-public utilities have to pay the standard fee (now $11,550) with a declaratory order petition?[332] and (5) will the Commission allow non-public utilities to include a stranded cost recovery provision similar to section 26 of the pro forma tariff?[333]

Oglethorpe asserts that the Commission should not use these procedures to assert jurisdiction over non-public transmitting utilities. Dairyland contends that requiring non-public utilities to invoke declaratory order or waiver proceedings just to assert the clear statutory protections contained in sections 211 and 212 is unwarranted.

TANC declares that the safe harbor provisions do not cure the problems created by reciprocity. It argues that the safe harbor provision expands the transmission access that must otherwise be offered by non-public utilities, *i.e.*, rather than just providing reciprocal service to the transmission provider, under the safe harbor provision, the non-jurisdictional entity must offer open access to any eligible customers.

Blue Ridge alleges that the safe harbor and waiver provisions face practical administrative problems. It asserts that a waiver itself will result in disputes and that the application of the waiver principle to non-public utilities is based on questionable statutory authority. It requests that the Commission add the following language to section 6 of the tariff: ''If the Transmission Customer is a non-public utility, the Transmission Provider must demonstrate a need for transmission service from such entity.'' (Blue Ridge at 39).

[332] NRECA raises comparable questions with respect to waiver procedures.

[333] *See also* TANC.

TAPS asks that the Commission accord the filing of a waiver application by a small non-public utility system, or inclusion in an application of a sworn statement of inapplicability, the same protections afforded larger non-public utility systems that file under the safe harbor mechanism.

Arkansas Cities ask the Commission to clarify that ''utilities like Arkansas Cities' members, which do not operate a control area, do not own 'transmission' facilities and primarily purchase energy for resale at retail are not subject to the transmission reciprocity condition contained in Order 888, and are also not required to file a request for a waiver from the requirements of Order 888 and 889.'' (Arkansas Cities at 18–19)

SWRTA and NWRTA ask the Commission to clarify that RTGs have the authority to issue limited waivers of the reciprocity requirements of Order Nos. 888 and 889 to qualifying non-public utility members of RTGs, and that the Commission will accord deference to an RTG's determination with respect to a non-public utility member's request for waiver of, or exemption from, these requirements.[334] They note that SWRTA's bylaws have a Commission-approved waiver process and disputes would go to arbitration or to the Commission.

Southern and EEI argue that public utilities should have a parallel ''safe harbor''—the right to seek a declaratory order as to whether the transmission service being offered by a non-public utility satisfies its reciprocity obligation.

Tallahassee asks that the Commission clarify the good faith assertion a public utility must make that the non-public utility has not met the reciprocity requirements. It asserts that the section 211 good faith request rules form an appropriate standard by which to measure a good faith assertion.

Commission Conclusion

Several entities raise procedural and jurisdictional concerns with respect to our safe harbor and waiver provisions. At the outset, we emphasize that this Commission does not have jurisdiction over non-public utilities under sections 205 and 206 and that the safe harbor mechanism and waiver provisions do not, and indeed cannot, give us such jurisdiction. Rather the safe harbor and waiver procedures are voluntary means for non-public utilities to obtain a Commission determination that they meet the reciprocity condition in the open access tariffs and thereby avoid

[334] WRTA supports NWRTA in NWRTA's rehearing request.

potential delays or denials of open access service based on allegations that the transmission requestor does not meet reciprocity. In *Santee Cooper,* issued subsequent to the Final Rule, the Commission recognized that it lacks jurisdiction under sections 205 and 206 over transmission rates, terms and conditions offered by non-public utilities, but explained that it has the authority to evaluate non-jurisdictional activities to the extent they affect the Commission's jurisdictional responsibilities.

We clarify that non-public utilities that disagree with a Commission determination are free to request rehearing of a Commission order, as occurred in *Santee Cooper.* If aggrieved by the Commission's final order, they may appeal under section 313 of the FPA. Also, with respect to the filing fee a non-public utility entity would have to pay in making a declaratory order request, the Commission in *Santee Cooper* explained that its regulations specifically exempt states, municipalities and anyone who is engaged in the official business of the Federal Government from filing fees.[335] Because of the nature of the safe harbor and waiver provisions, we will also waive the filing fee for declaratory orders for all other non-public utilities in these circumstances.

As to the question of how closely a reciprocal tariff will have to conform to Order No. 888, the Commission determined in *Santee Cooper* that:

> As part of its compliance filing * * * the Authority must submit a single tariff that conforms to the Open Access Rule *pro forma* tariff.[336]

The Commission further explained that ''[t]he Open Access Rule requires that reciprocity tariffs contain terms and conditions which substantially conform or are superior to those in the Open Access Rule *pro forma* tariff.'' [337] We clarify, however, that in that case the utility chose to offer an open access tariff, whereas Order No. 888 provides, as a condition of service, that reciprocal access be offered to only those transmission providers from whom the non-public utility obtains open access service. Therefore, a non-public utility may so limit the use of any voluntarily offered tariff, as long as the tariff otherwise substantially conforms to the pro forma tariff. We also note that non-public utilities are free to enter into bilateral agreements to satisfy the reciprocity condition. With respect to such bilateral reciprocal agreements, we must leave these agreements to case-by-case determinations. Which terms and conditions may be necessary for a non-public utility to provide reciprocal service to the public utility in a bilateral agreement is necessarily a fact-specific matter not susceptible to resolution in a generic rulemaking proceeding. Additionally, we clarify that non-public utilities may include stranded cost recovery provisions in any reciprocity tariffs that they may file.[338]

In response to TANC's concern that the safe harbor provision expands the transmission access that must otherwise be offered by non-public utility entities, and Blue Ridge's concern that the safe harbor and waiver provisions raise practical administrative problems, we emphasize that both of these procedures are purely voluntary and a non-public utility can avoid any perceived problems simply by not taking part in either process. We note that several entities have voluntarily availed themselves of these procedures without any apparent hardships.[339]

Arkansas Cities' various waiver requests are best addressed on a case-by-case basis that permits a full airing of the factual circumstances surrounding each entity seeking a waiver. As we explained in a recent order, ''the Commission will not address waiver requests in a generic rulemaking proceeding, but will require entities seeking waiver of all or part of Order Nos. 888 and 889 to submit separate, fact-specific requests. * * *'' [340]

EEI's and Southern's request that public utilities be provided a parallel ''safe harbor'' (*i.e.,* the right to seek a declaratory order as to whether the transmission service being offered by a non-public utility satisfies its reciprocity obligation) is denied. In the Final Rule, we explained that a public utility may refuse to provide open access transmission service to a non-public utility if its denial is based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements. [341] Moreover, a public utility can file a petition to terminate transmission service if a non-public utility is violating the reciprocity condition of its open access service agreement with the public utility.[342]

In response to SWRTA and NWRTA's request to clarify that RTGs have the authority to issue limited waivers of the reciprocity conditions of the Order No. 888 pro forma tariffs, we recognize that RTGs have procedures in place to resolve disputes that may arise concerning a non-public utility member's request for service from a public utility member. Because RTGs have these dispute resolution procedures in place, we clarify that RTGs, which are in themselves reciprocal voluntary arrangements, may determine whether to apply reciprocity between and among member public utilities and member non-public utilities, subject to the RTG dispute resolution procedures authorized by this Commission.

Rehearing Requests

Retail Wheeling

Dairyland contends that the Commission improperly requires a non-public utility to provide retail wheeling if it uses the open access tariff of a public utility that allows retail access either voluntarily or as part of a state-mandated program.

Commission Conclusion

Contrary to Dairyland's contention, nothing in the Final Rule requires a non-public utility to provide retail wheeling. Section 212(h) of the FPA explicitly prohibits the Commission from ordering retail transmission directly to an ultimate consumer. If a non-public utility offers reciprocal service, its tariff would have to include the same explicit provision contained in the pro forma tariff, which states that an eligible customer cannot obtain transmission that would violate section 212(h) of the FPA, unless pursuant to a state program that requires the transmission provider to offer such wheeling.

Rehearing Requests

OASIS

Southern argues that the Commission should explicitly require that non-public utilities must comply with Order No. 889 as part of the reciprocity obligation.

Commission Conclusion

We agree with Southern and, as discussed above, absent a waiver, will

[335] 75 FERC at 61,694–95 (citing 18 CFR 381.108).

[336] 75 FERC at 61,701.

[337] *Id.*

[338] 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.

[342] 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.

require non-public utilities to comply with Order No. 889 as part of the reciprocity obligation.

Rehearing Requests

Foreign Entities

In the Open Access Rule, we decided that a foreign entity that otherwise meets the eligibility criteria should be able to obtain service under a United States public utility's open access tariff. However, like United States non-public utilities (which also are not under our section 205–206 jurisdiction), a foreign entity that owns or controls transmission facilities and that takes transmission service under a United States public utility's open access tariff must comply with the reciprocity provision in the tariff.[343] The reciprocity provision ensures that when a public utility provides service under its open access tariff to a transmission-owning entity that is not subject to the open access requirement, the public utility will be able to receive service in turn from that entity. In our discussion of the reciprocity provision, we pointed out that if a non-jurisdictional entity that owns or controls transmission does not wish to provide service to the public utility, it can choose not to use the public utility's open access tariff and can instead seek voluntary service from the public utility on a contractual basis.[344]

On rehearing, Ontario Hydro argues that the Commission has ''unilateral[ly] impos[ed]'' the reciprocity requirement on foreign entities in violation of the North American Free Trade Agreement (NAFTA).[345] It declares that

> [u]nder the principle of national treatment, the citizens of each party to NAFTA * * * are allowed the same market access within another treaty party's market as is provided to the citizens of such other party. A party to these agreements cannot withhold access to its market by conditioning it upon receipt of equal access into the market of another party, because the result would be market access less favorable for the other party * * * than that accorded the party's own citizens.[346]

Ontario Hydro claims that the Open Access Rule ''makes open access the law of the land for wholesale transmission service within the United States * * *'' and that Canadian entities are thus entitled to such access on an unconditional basis.[347] Next, it accuses the Commission of trying to ''coerce'' Canada to ''conform its market access policy'' to United States policy and of ''impos[ing] U.S. regulatory policies'' on Canadian markets.[348] Finally, Ontario Hydro argues that even aside from the NAFTA issue, under the FPA the Commission does not have jurisdiction over foreign entities and thus cannot require reciprocity.

Commission Conclusion

We disagree with Ontario Hydro's claim that NAFTA's national treatment principle requires us to allow a Canadian transmission-owning entity (or its corporate affiliate) to take advantage of a United States public utility's open access tariff—a tariff we have required the utility to adopt—while simultaneously refusing to allow the United States utility to use the Canadian entity's transmission facilities. NAFTA's national treatment principle requires that each signatory ''accord national treatment to the goods'' of other signatories in accordance with Article III of the General Agreement on Tariffs and Trade (GATT).[349] National treatment means that the United States ''must not discriminate between foreign and domestic energy on the basis of nationality * * *'' and that Canadian electricity must be treated ''no less favorabl[y] than U.S. electricity, under all U.S. laws and rules respecting the sale, * * * distribution, and use of * * * electricity.'' Thus, this Commission must accord Canadian energy supplies treatment that is no less favorable than the treatment accorded United States supplies.[350] Ontario Hydro's interpretation, however, would twist this principle into a requirement that Canadian entities be treated better than United States entities, including United States non-public utilities that are subject to the reciprocity condition.[351]

Under Order No. 888, all public utility open access tariffs contain a reciprocity condition that applies to all users of the tariff within the United States, including United States non-public utilities, unless the condition is waived either by the Commission or the public utility provider. Under the reciprocity condition, non-public utilities do not have to offer an open access tariff (i.e., a tariff that offers transmission service to any eligible customer), but rather must offer comparable transmission services only to those transmission providers whose open access tariffs the non-public utility uses.[352] The same condition applies to foreign utilities. Thus, Ontario Hydro is in plain error in arguing that application of the reciprocity condition to foreign entities would result in less favorable treatment than that accorded to United States citizens. Ontario Hydro's reading of NAFTA would place transmission-owning Canadian entities (or their corporate affiliates) in a *better* position than any domestic entity; not only would Canadian entities not be subject to the open access requirement, but, unlike domestic non-public utilities, they would be able to use the open access tariffs we have mandated without providing *any* reciprocal service. Ontario Hydro has cited no precedent demonstrating that NAFTA imposes such an unreasonable requirement.[353]

Moreover, we are not ''coercing'' Canada into adopting our policies or ''imposing'' open access on Canadian entities; we are simply placing the same condition on a Canadian entity's use of a United States utility's open access tariff as on a domestic non-public utility's use of that tariff. However, consistent with the approach we have taken in other contexts involving foreign utilities seeking to transact in United States electricity markets, we are amenable to a variety of approaches for Canadian utilities to meet the reciprocity condition.[354]

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

[344] 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.

[348] 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.

[350] 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.

[351] 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.

[353] 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

Continued

Ontario Hydro is also wrong in its claim that even aside from NAFTA, we lack authority under the FPA to require reciprocity when a foreign entity wishes to use a domestic utility's open access tariff. Just as we are not asserting jurisdiction over domestic non-public utilities under sections 205 or 206 of the FPA, we also are not asserting jurisdiction over foreign entities. Rather, we are simply placing the same reasonable and fair condition on both types of entities' uses of the transmission ordered in the Final Rule.[355]

Rehearing Requests

Unconstitutional as Applied to NE Public Power District

NE Public Power District asserts that the reciprocity provision as applied to NE Public Power District (a public corporation and political and governmental subdivision under Nebraska law) is unconstitutional. It argues that reciprocity would intrude into the sovereignty of Nebraska and would negate the decision of Nebraska's citizens to use their own governmental institutions to provide electric service. Moreover, contrary to the Commission's assertion, NE Public Power District states that it does not have a real choice in deciding whether to use the transmission service of public utilities. Because it is beyond the power of Congress to compel Nebraska to adopt a federally prescribed program for providing its citizens with electric utility services, NE Public Power District argues that it must follow that a federal agency lacks the constitutional and statutory authority to compel a Nebraska state instrumentality to adopt a FERC-drafted tariff and to modify its contracts.

NE Public Power District states that section 201(f) of the FPA exempts state-owned utilities from the jurisdiction of the Commission and that sections 211–213 are the exclusive means by which the Commission can require non-public utilities to perform involuntary transmission service. It asserts that the Commission should exempt publicly-owned utilities from application of the Final Rule and notes that virtually all non-public utility entities are, or soon will be, voluntary participants in power pools, RTGs, or other similar organizations. Thus, NE Public Power District argues that there is no compelling public interest to require these entities now to submit to the reciprocity provision.

In addition, NE Public Power District argues that compliance would conflict with Nebraska law and bond covenants, *i.e.,* Nebraska law, for example, does not permit a public entity to agree in advance of a dispute to submit to binding arbitration. NE Public Power District states that it is bound by a bond covenant that prohibits it from rendering service free of charge and requires that a customer's default must be cured within a specific time. It also argues that these requirements are in conflict with section 7.3 of the pro forma tariff.

Commission Conclusion

Under the Supremacy Clause of the Constitution, Nebraska law cannot and does not override this Commission's authorities and responsibilities under the FPA. Rather, this Commission has exclusive jurisdiction over the rates, terms and conditions of transmission in interstate commerce by public utilities, including reciprocity conditions contained in the tariffs of public utilities. Nothing in Order No. 888 compels Nebraska to adopt a ''federally prescribed program.'' While we do not have full jurisdiction over non-public utilities,[356] our actions in regulating jurisdictional matters may impact those who wish to use jurisdictional services or to enter into agreements with public utilities. The Commission's obligation is to ensure that public utilities' services are just and reasonable and not unduly discriminatory or preferential and non-public utilities can choose to comply or not regarding matters within our exclusive jurisdiction. Moreover, as we explained above, NE Public Power District can seek waiver of the reciprocity condition on a case-by-case basis.

Rehearing Requests

QF Position

American Forest & Paper asks the Commission to clarify that QFs are exempted from the reciprocity requirement or, in the alternative, grant them a blanket waiver. It states that QFs are not allowed to provide transmission service for third parties. Moreover, it asserts that there are unlikely to be many requests for transmission service over a QF's interconnection line and such cases should be handled on a case-by-case basis.

Commission Conclusion

We will not grant QFs an exemption from the reciprocity condition or grant them a blanket waiver, but will address this issue on a case-by-case basis if and when it arises. Because most QFs own little transmission, it is not likely that they will be asked to provide reciprocal service.

Furthermore, in a proceeding involving a QF, we explained that use of a QF's transmission line by a non-QF would not affect its QF status:

> It would not fail the ownership test for QF status because, consistent with the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA), the Oxbow Geothermal facility would continue to be ''owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities).'' 16 U.S.C. § 796(18)(B)(1994).[357]

If a QF that owns, controls or operates interstate transmission facilities seeks open access transmission from a public utility, it must agree to provide reciprocal service to that public utility. Of course, the QF could file a waiver request in a separate proceeding, as set forth in the Final Rule and clarified in a subsequent order.[358]

Rehearing Requests

Tax-Exempt Financing Issues

Reciprocity and Private Activity Bonds

EEI asks the Commission to require non-public utilities claiming that their tax status is a bar to granting reciprocity to substantiate such claim in a safe harbor proceeding and to take reasonable measures to request the IRS to allow them to provide reciprocal service while retaining their tax status. If the Commission decides not to require a safe harbor proceeding, EEI requests that the Commission require non-public utilities to substantiate their tax concerns and to demonstrate to each public utility from which they seek service that they are actively pursuing

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).

[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).

the issue with the IRS.[359] It also urges that the Commission require any request for exemption from the reciprocity requirement that is based on jeopardy to tax-exempt status be filed with the Commission as part of a request for declaratory order in a safe harbor proceeding. Moreover, it requests that the Commission require a non-public utility to specifically identify the facilities it cannot use without jeopardizing its tax-exempt financing and to provide copies of, and specifically reference the tax provisions in, the related financing agreements that embody this restriction.

Centerior asks that the Commission condition receipt of open access transmission service by municipal utilities upon the elimination or mitigation of tax subsidies and regulatory inequities. Southern maintains that tax-exempt status can remain undisturbed if non-public utilities do not seek open access transmission service from public utilities. Thus, Southern asserts, non-public utilities can weigh the benefits of transmission service under the Final Rule against the potential threat to their tax benefits, and make the choice that serves their best interest. At a minimum, it argues, the Commission should await the determinations of the IRS before finalizing this aspect of the reciprocity provision, rather than confer yet another unique benefit on non-public utilities.[360]

CAMU asks that the Commission defer reciprocity obligations until the IRS has clarified the status of private use limitations within the context of transmission access. Otherwise, CAMU asserts, innocent investors could suffer penalties because the Commission moved too quickly on this sensitive issue.

Local Furnishing Bonds

Local Furnishing Utilities and ConEd state that section 5.1 of the pro forma tariff applies to ''Transmission Service,'' which is defined in section 1.48 to include point-to-point service, but not network service. They ask the Commission to clarify that the phrase ''transmission service'' also applies to network service.

Local Furnishing Utilities and ConEd ask that the Commission confirm that all costs associated with the loss of tax-exempt status, including defeasing, redeeming, and refinancing tax-exempt bonds, will be considered costs of providing transmission that must be borne by the customer for whom the transmission is provided. They state that defeasance and refinancing costs are just as attributable to the particular transmission service causing such defeasance or redemption as the costs of expanding the system are attributable to the service that cause the need for such expansion. They ask that the Commission clarify that a transmission provider may include in its tariff a provision permitting the recovery of such costs, even if a filing under section 205 of the FPA is required. ConEd asserts that if a customer does not want to pay costs associated with the loss of tax-exempt status on the bonds, the Commission should allow the transmission provider to decline to provide the requested service.

Local Furnishing Utilities and ConEd also assert that section 5.2 of the pro forma tariff should be clarified to state that issuance of a section 211 order by the Commission is a condition precedent to the provision of transmission service. Local Furnishing Utilities states that there is a question whether the Commission should insist on waiver of the issuance of a proposed order under section 212(c). According to Local Furnishing Utilities, the negotiations that normally would follow the issuance of a proposed order are likely to provide the only opportunity to demonstrate and review the costs associated with the loss of tax-exempt status.

Local Furnishing Utilities and ConEd assert that sections 5.1 and 5.2(i) of the pro forma tariff improperly limit the safe harbor protection of section 1919 of EPAct to transmission providers that financed ''transmission facilities'' with local furnishing bonds. Because of this, they assert, the safe harbor is not available to ConEd, all of whose local furnishing bonds have been used to finance its distribution system. They argue that section 5.1 should apply to service that would jeopardize the tax-exempt status of bonds that finance distribution or generation, as well as transmission, facilities. NE Public Power District contends that section 5.2(ii) should be amended ''to make it clear that interim service need not be begun if rendering the service would endanger the tax-exempt status of the provider's bonds, unless the customer agrees to bear the financial consequences of such loss of tax-exempt status and has the wherewithal to do so.'' (NE Public Power District at 22–23).

SoCal Edison argues that local furnishing utilities should be required to comply with the Final Rule without any exception based upon their tax-exempt bonds.

Commission Conclusion

Private Activity Bonds

As we explained in Order No. 888, it is not our purpose to disturb Congress's and the IRS's determinations with respect to tax-exempt financing. With respect to private activity bonds, we reaffirm our finding that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities. We remain hopeful that the IRS in its private activity bond rulemaking will, to the maximum extent possible, remove regulatory impediments that limit the ability of industry participants to provide reciprocal open access. As we indicated in Order No. 888, after the IRS acts, we will reexamine our policy to ensure that the reciprocity condition is applied broadly to achieve open access without jeopardizing tax-exempt financing.[361]

We will reject the request of EEI and Tucson Power that the Commission require non-public utilities to substantiate in a safe harbor proceeding a claim that their tax status is a bar to granting reciprocity. As we stated in Order No. 888, if a non-public utility has sought a declaratory order on a voluntarily-filed tariff, we request that it identify the services, if any, that it cannot provide without jeopardizing the tax-exempt status of its financing. However, we cannot require that a non-public utility use the safe harbor mechanism, whether to file a reciprocal tariff with the Commission or to substantiate a claim as to loss of tax-exempt status. As we explain above, the safe harbor procedure is a voluntary means for non-public utilities to obtain a Commission determination that they meet the reciprocity condition in the open access tariffs and thereby avoid potential delays or denials of open access service based on allegations that the transmission requestor does not meet reciprocity.

Nevertheless, just as we believe that it is appropriate to condition the use of public utility open access tariffs on the

[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).

agreement of the tariff user to provide reciprocal access to the transmission provider, we also believe it is appropriate to condition the use of public utility open access tariffs on the agreement of the non-public utility tariff user to substantiate any claim that providing reciprocal transmission service would jeopardize the tax-exempt status of its financing. The non-public utility can provide such substantiation by identifying for the customer the services that it cannot provide without jeopardizing its tax-exempt financing.[362]

Southern suggests that tax-exempt status can remain undisturbed if non-public utilities do not seek open access transmission service from public utilities and, therefore, that non-public utilities can weigh the benefits of transmission service under the Rule against the potential threat to their tax benefits. We believe it is important to remember why we required open access in the first place—as a remedy for undue discrimination in transmission services in interstate commerce. Southern would force a non-public utility to give up a Congressionally-mandated right as a condition to taking open access transmission. Clearly Southern's suggestion is misplaced and overbroad.[363] For this reason, we believe that our decision not to require reciprocal service if providing such service would jeopardize the non-public utility's tax-exempt financing—pending action by the IRS in its private activity bond rulemaking—is appropriate for the time being.[364] We reiterate that we will reexamine our policy after the IRS acts. As we state above, we believe that ultimately the public interest is best served by nationwide open access.

Local Furnishing Bonds

We clarify, in response to Local Furnishing Utilities and ConEd, that the reference to ''Transmission Service'' in section 5.1 of the pro forma tariff was intended to be to ''transmission service,'' and thereby to apply to point-to-point service as well as network service. We have revised section 5.1 accordingly.

We further clarify that all costs associated with the loss of tax-exempt status, including the costs of defeasing, redeeming, and refinancing tax-exempt bonds, are properly considered costs of providing transmission services. Therefore, a customer that takes service, understanding that such service will result in loss of tax-exempt status, shall be responsible for such costs to the extent consistent with Commission policy, and a transmission provider may include in its tariff a provision permitting it to seek recovery of such costs. We clarify that if the transmission customer is not willing to pay the costs associated with the transmission provider's loss of tax-exempt status, the transmission provider will not be required to provide the requested service.[365]

Local Furnishing Utilities and ConEd also ask the Commission to revise section 5.2 of the pro forma tariff to state that issuance of a section 211 order by the Commission is a condition precedent to the provision of transmission service. Under the tariff provision adopted by Order No. 888 to address situations in which the provision of transmission service would jeopardize the tax-exempt status of any local furnishing bonds used to finance a local furnishing utility's facilities, the customer requesting transmission service would tender an application under section 211 of the FPA. Within ten days of receiving a copy of the section 211 application, the transmission provider ''will waive its rights to a request for service under Section 213(a) of the [FPA] and to the issuance of a proposed order under Section 212(c) of the [FPA] and shall provide the requested transmission service in accordance with the terms and conditions of this Tariff.'' [366] We clarify that the Commission, upon receipt of the transmission provider's waiver of its rights to a request for service under section 213(a) and to the issuance of a proposed order under section 212(c), shall issue an order under section 211.[367] Upon issuance of the order under section 211, the transmission provider shall be required to provide the requested transmission service in accordance with the terms and conditions of the tariff. Section 5.2 of the pro forma tariff has been revised accordingly.

Local Furnishing Utilities and ConEd also contend that the language of sections 5.1 and 5.2(i) of the pro forma tariff improperly limits the safe harbor protection of section 1919 of EPAct to transmission providers that financed transmission facilities with local furnishing bonds. ConEd expresses concern that although all of its electric local furnishing bonds have been used to finance its distribution system, the test as to whether those bonds have been used for the ''local furnishing'' of electricity is based in part on whether ConEd has been a ''net importer'' of energy into its service territory. As a result, ConEd argues that the use of its transmission system to wheel power from a generating source located inside ConEd's service territory to a customer located outside its service territory could cause ConEd to violate the net importer rule and thereby lose the tax exemption for the bonds used to finance its distribution system. ConEd asks the Commission to modify sections 5.1 and 5.2 of the pro forma tariff to make clear that those provisions apply to transmission providers that have financed any ''facilities'' (*i.e.*, distribution and generation, not just transmission, facilities) with local furnishing bonds.

As we explained in Order No. 888, we believe the local furnishing bonds

[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.

[364] 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).

[367] 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.

provision in section 5 of the pro forma tariff is necessary and appropriate so that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime. If the provision of transmission service pursuant to Order No. 888 would result in the loss of tax-exempt status for local furnishing bonds, regardless of whether the facilities financed with those bonds are transmission, distribution, or generation facilities, it is our intent that the provisions of section 5 would apply. Thus, we clarify in response to ConEd and Local Furnishing Utilities that, to the extent the provision of transmission under an open access tariff would jeopardize the tax-exempt status of local furnishing bonds used to finance distribution or generation facilities (even if no transmission facilities were financed with such bonds),[368] such situation would fall within the reference to ''facilities that would be used in providing . . . transmission service'' contained in sections 5.1 and 5.2(i). This is so because the loss of tax-exempt status in such circumstances would be directly attributable to the provision of transmission services under the Rule.

Further, we said in Order No. 888 that ''we will require any public utility that is subject to the Open Access Rule that has financed transmission facilities with local furnishing bonds to include in its tariff'' a provision similar to section 5 of the pro forma tariff.[369] We clarify that we did not intend by this statement that the section 5 local furnishing bonds provision would only apply to public utilities that have financed transmission facilities with local furnishing bonds, and not those that have financed generation and distribution facilities with such bonds. As we explain above, it is our intent that the provisions of section 5 apply if the provision of transmission service pursuant to an open access tariff would result in the loss of tax-exempt status for local furnishing bonds, regardless of whether the facilities financed with those bonds are transmission, distribution, or generation facilities.

Rehearing Requests

Unfunded Mandates Reform Act

NE Public Power District[370] argues that the final regulations adopted in this proceeding ''constitute[] an unfunded mandate under the Unfunded Mandates Reform Act of 1995 * * *.''[371] It declares that Order No. 888 imposes significant costs upon local governments and that the Commission was required under the Unfunded Mandates Reform Act to consider the financial impact of its rulemaking upon state and local governments and to prepare and issue as part of its rulemaking process a statement containing certain specified analyses and estimates concerning this matter and a description of its pre-issuance consultations with state and local government authorities. To support its argument NE Public Power District relies upon: (a) Executive Order No. 12875, *Enhancing the Intergovernmental Partnership* (Executive Order);[372] and (b) the Unfunded Mandates Reform Act of 1995 (the Act).[373]

Commission Conclusion

We disagree with NE Public Power District. The Executive Order applies to every ''executive department * * * [and] agency. * * * ''[374] It defines ''executive agency'' as ''any authority of the United States that is an 'agency' under 44 U.S.C. § 3502(1), *other than those considered to be independent regulatory agencies, as defined in 44 U.S.C. § 3502 (10).*''[375] In section 3502(10), the Federal Energy Regulatory Commission is defined as an independent regulatory agency. As a result, the Executive Order does not apply to the Commission.

The Act similarly applies to federal agencies, but, as with the Executive Order, does not apply to independent regulatory agencies.[376] Although the Act does not define ''independent regulatory agency,'' there is no indication that Congress intended to exclude the Commission from the definition. In fact, in all instances in which Congress has defined the term ''independent regulatory agency'' of which we are aware, the Commission has been included.

As noted, the Commission is defined as an independent regulatory agency in Title 44 U.S.C. Also, Title 42 U.S.C. § 7176 provides that:

> For the purposes of chapter 9 of title 5, United States Code * * * [Executive Reorganization], the [Federal Energy Regulatory] Commission shall be deemed to be an independent regulatory agency.[377]

Accordingly, we find that the Commission is an independent regulatory agency as used in the Act; therefore, it is not covered by the Act.

Moreover, even if the Act applied to the Commission, the Final Rule will not impose a Federal mandate on state, local or tribal governments.

Section 305 of the Act defines a ''Federal mandate'' as:

> any provision in [a] statute or regulation or [in] any Federal court ruling that *imposes an enforceable duty* upon State, local, or tribal governments[,] including a condition of Federal assistance or a duty arising from participation in a voluntary Federal program.[378]

The Open Access Final Rule imposes requirements only on certain public utilities[379] and, pursuant to section 201(f) of the FPA, state and local

[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.

[371] 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.

[372] 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.

[373] 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).

[375] 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.

governments, and their agencies, authorities and instrumentalities, are not public utilities. Additionally, although the Final Rule will allow public utilities' transmission tariffs to contain reciprocity provisions in order to ensure that public utilities offering open access transmission to others can obtain similar service from open access users, the reciprocity provision is not an *enforceable duty.* A duty is mandatory; it is an obligation to perform and is compulsory.[380] The reciprocity provision is merely a condition of receiving a benefit, *i.e.*, open access transmission service from a public utility.[381] There is no requirement that NE Public Power District promulgate an open access tariff and apply to FERC for a declaratory order. Moreover, as we explained above, non-public utilities, such as NE Public Power District, are free to seek from a public utility a waiver of the open access tariff reciprocity condition.

With regard to the Stranded Cost Final Rule, while it applies to non-public utilities as well as public utilities, it does not impose a duty on any entity since it merely permits public utilities and transmitting utilities to seek recovery of certain costs. As a result, since the Open Access and Stranded Cost final rules will not impose an enforceable duty on state, municipal or tribal power agencies such as NE Public Power District, the rules are not Federal mandates as defined in the Act.

Because the Unfunded Mandates Reform Act of 1995 does not apply to the Commission and, in any event, the Open Access/Stranded Cost final rules do not impose Federal mandates on state, local or tribal governments, we reject NE Public Power District's argument that the Unfunded Mandates Reform Act of 1995 is applicable here.

5. Liability and Indemnification

In the Final Rule, the Commission explained that the indemnification provision was broken into two parts (set forth in section 10.1 (Force Majeure) and section 10.2 (Indemnification) of the pro forma tariff).[382] The Commission explained that the first part is a force majeure provision which provides that neither the transmission provider nor the customer will be in default if a force majeure event occurs, but also provides that both the transmission provider and customer will take all reasonable steps to comply with the tariff despite the occurrence of a force majeure event.

The Commission explained that the second portion of the provision provides for indemnification against third party claims arising from the performance of obligations under the tariff. The Commission limited the indemnification portion of the provision so that it is only the transmission customer who indemnifies the transmission provider from the claims of third parties. The Commission explained that the revised provision provides that the customer will not be required to indemnify the transmission provider in the case of negligence or intentional wrongdoing by the transmission provider.

Rehearing Requests

A number of utilities argue that the Commission has expanded transmitter liability beyond the existing standard in the industry, *i.e.*, gross negligence.[383] They assert that the Commission has provided no basis to subject transmission providers to liability, including consequential damages, due to ordinary negligence. KCPL points out that 21 of 25 states addressing this issue hold that a utility should not be liable for ordinary negligence. It declares that society will be worse off in litigation expenses and wasted human resources if utilities are held liable for simple negligence. It adds that the electric industry is much more susceptible to liability from interruptions of service than gas pipelines (refuting the Commission's reliance on *Pacific Interstate Offshore Company*, which it states is traceable to *United Gas Pipeline Co.* v. *FERC*, 824 F.2d 417 (5th Cir. 1987)). Florida Power Corp asks the Commission to modify section 10.2 to provide that a customer must indemnify the transmission provider except where a finder of fact determines that the transmission provider has committed gross or intentional wrongdoing. It also argues that the Commission should eliminate liability of both the transmission provider and the customer to the other for consequential damages.

Southern argues that the exception language in section 10.2 should be changed to ''except where a court has determined that the Transmission Provider has engaged in intentional wrongdoing or has been grossly negligent.'' (Southern at 20–21). Southern also argues that the Commission should limit consequential damages arising from negligence in the operation of the transmission system.

Puget asserts that the exception language in section 10.2 should be changed to ''except in cases of and to the extent of comparative or contributory negligence or intentional wrongdoing by the Transmission Provider.'' (Puget at 18). It also asserts that the Commission should exclude liability for special, incidental, consequential, or indirect damages.

EEI argues that the Commission should add a new section 10.3: ''If the Transmission Provider is found liable for any damages associated with this Tariff, those damages shall be limited to direct damages, and the Transmission Provider shall not be liable for any special, indirect or consequential damages of any nature by virtue of the transactions conducted under this Tariff.'' (EEI at 26).

Coalition for Economic Competition argues that the Commission should modify section 10.2 to provide that the transmission provider will not be liable to a transmission customer or any third party for damages caused by interruptions or irregular or defective service, except if gross negligence or wilful misconduct caused such damages.[384] Coalition for Economic Competition asserts that the definition of force majeure should include ordinary negligence and asks that the Commission clarify that a utility is not liable for force majeure events.

CCEM also argues that transmission customer indemnity in section 10.2 should attach only to legal actions brought by customers of the transmission customer or third-party beneficiaries of those customers.

On the other hand, TDU Systems argues that the indemnity provision unfairly provides the transmission provider with virtually total indemnification for acts on its side of the delivery point, but provides no reciprocal protection to the transmission customers for damage incurred on the customers' system in connection with purchasing the transmission provider's services.

[380] 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).

[381] 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'').

CSW Operating Companies asks the Commission to revise the pro forma tariff to provide that a transmission provider will not be liable for errors in an estimate made in good faith and in accordance with its published procedure. They propose the following language:

Information posted on the OASIS concerning the availability of transfer capability will be based on the Transmission Provider's best estimates given the information readily and actually available to the transmission provider. No such estimate will be binding on the Transmission Provider for any purpose.

Alternatively, they ask the Commission to clarify that as long as a transmission provider in good faith follows its published methodology for determining ATC and TTC it will be deemed not to be negligent.

Commission Conclusion

The purpose of the force majeure provision in the pro forma tariff is to ensure that neither the customer nor the transmission provider is held in default in the event of an unpredictable and uncontrollable force majeure event. It was not the Commission's intention that the force majeure clause provide an avenue for a party to claim that it is excused from liability for its own negligence. A force majeure event does not include an act of negligence or intentional wrongdoing. The pro forma tariff will be changed accordingly.[385]

The purpose of the indemnification provision is to allocate the risks of a transaction, and the costs associated with those risks, to the party on whose behalf the transaction has been conducted, the transmission customer. As the tariff does not obligate the customer to perform services on behalf of the transmission provider, there is no comparable basis for imposing an indemnification obligation on the transmission provider.[386]

As is explained in the Final Rule, the Commission does not believe it appropriate to extend the indemnification obligation so that it would apply even in cases where the transmission provider has been negligent. The contention that electric transmission outages are either more frequent or more costly than gas outages does not serve to distinguish the electric transmission situation from the gas pipeline cases in which the Commission has found that indemnification clauses should not protect the pipeline owner from its own negligence.[387] In either case, it would be inappropriate to require the customer to indemnify the transmission provider from damages arising from the transmission provider's own negligence. We note, however, that liability is a separate issue from indemnification. Despite the absence of indemnification protection, there is nothing in the indemnification provision that would preclude transmission providers from relying on the protection of state laws, when and where applicable, protecting utilities or others from claims founded in ordinary negligence.

With respect to the issue of consequential and indirect damages, the indemnification provision already provides protection to the transmission provider from consequential and indirect damage claims by third parties except in cases of negligence or intentional wrongdoing by the transmission provider. The Commission sees no need to further extend this protection. Again, we note that liability is a separate issue from indemnification, and that nothing in these provisions precludes transmission providers or customers from relying, when and where such law is applicable, on the protection of statutes or other law protecting parties from consequential or indirect damages.

Furthermore, we will not revise the pro forma tariff, as requested by CSW Operating Companies, to provide that a transmission provider will not be liable for errors in an estimate made in good faith or in accordance with its published procedure. We believe that a utility should have no different a liability standard for operating an OASIS than for its other operations.[388]

6. Umbrella Service Agreements

The Commission received requests for clarification regarding this issue, which was not specifically addressed by the Commission in the Final Rule.

Rehearing Requests

SoCal Edison argues that it is too burdensome to require a separate Completed Application and a separate Service Agreement to be executed for each individual service transaction for short-term firm and non-firm transmission service (and filed with the Commission). SoCal Edison contends that requiring a separate service agreement for each short-term firm transaction to be filed with the Commission will stifle transactions in the short-term market. It indicates that it suggested a simpler approach in Docket No. ER96–222–000 that would establish a non-transaction specific Service Agreement and a Completed Application that would contain the specific transaction information, but would not be filed with the Commission, but would be made available for audit.[389]

Commission Conclusion

SoCal Edison misinterprets the tariff provisions regarding service agreements for non-firm point-to-point transmission service. Tariff section 14.5 details the treatment of service agreements for non-firm transmission service:

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it *first* submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the tariff. (Emphasis added)

Moreover, in tariff section 18 (Procedures for Arranging for Non-Firm Point-To-Point Transmission Service) requires that a separate service agreement be executed for each individual service transaction as claimed by SoCal Edison. In the pro forma tariff, the Commission established a non-transaction specific (or ''umbrella'') service agreement in an attempt to streamline the application procedures for non-firm point-to-point transmission service. Therefore, the service agreement for non-firm point-to-point transmission service need only be executed and filed with the Commission once, when the transmission customer first applies for non-firm point-to-point transmission service. Subsequent non-firm transactions by the same customer only require the submission of a completed application (as provided in tariff sections 18.1 and 18.2) by that customer, which will be submitted via the transmission provider's OASIS (when the OASIS is fully implemented). Accordingly, no changes are required to

[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.

the application procedures for non-firm point-to-point service.

However, we do find SoCal Edison's arguments persuasive that streamlined procedures should also be applied to applications for firm point-to-point transmission service with a duration of less than one year (short-term firm). We agree that there is no compelling reason to require the submission of separate service agreements for every short-term firm transaction. Accordingly, we will adopt an ''umbrella'' service agreement approach (as is currently used for non-firm point-to-point transactions) and require a service agreement of general applicability to be filed with the Commission when the first short-term firm transaction is arranged between the transmission provider and customer.

In order to facilitate an umbrella service agreement approach for short-term firm transmission service, minor modifications have been made to several sections of the pro forma tariff [390] as well as to Attachment A (Form of Service Agreement For Firm Point-To-Point Transmission Service). Notably, pages 3 and 4 of the service agreement, containing transaction specific information, is now required only for long-term firm point-to-point transmission service.

7. Other Tariff Provisions

a. Minimum and Maximum Service Periods

In the Final Rule, the Commission adopted a one-day minimum term for firm point-to-point service.[391] The Commission also concluded that it will not specify a maximum term for either firm point-to-point or network transmission service. However, the Commission modified the tariff to require that an application for transmission service specify the length of service being requested.

Rehearing Requests

CCEM states that a competitive market for hourly trades should be allowed to develop (transmission and ancillary services). It argues that contrary to the Commission's goal of comparability, the Rule effectively allows only incumbent utilities to participate in hourly markets on behalf of their own or network loads (citing section 13.1 of the pro forma tariff).

American Forest & Paper argues that firm and non-firm service should be made available on an hourly basis and that the Commission should assure that utilities make non-firm service available.

Commission Conclusion

It is unclear as to what hourly ''trades'' CCEM is referring. If CCEM is referring to off-system *sales*, the transmission provider is obligated to take transmission for any off-system sales under point-to-point transmission service under its tariff. Inasmuch as the tariff does not require the provision of hourly firm transmission, in order to provide itself with hourly firm transmission, the transmission provider would either: (1) reserve firm point-to-point service on a daily basis in order to participate in the hourly market or (2) propose in a section 205 filing to modify its tariff to voluntarily provide hourly firm point-to-point service. Under either circumstance, comparability would be maintained as all point-to-point customers would have equal access to the hourly market.

If CCEM is referring to *purchases*, hourly economy purchases by the transmission provider on behalf of its native load customers are also available on a comparable basis to network customers. However, if CCEM is referring to specific purchases made on behalf of a particular wholesale customer, this resale must be provided under point-to-point transmission service, as described above.

The Commission has rejected hourly firm point-to-point transmission service as a mandatory service to be provided under the Tariff.[392] Many entities would not oppose hourly firm service if afforded a lower priority, *i.e.*, if they were curtailed before longer-term firm services. However, with this lower priority there may be little or no difference between the pro forma tariff non-firm service and curtailable firm hourly service. The Commission adopted the one-day minimum term for firm service to address concerns that customers would engage in ''cream skimming'' by taking firm service only during the hours at the daily peak while taking non-firm service for other hours, and thereby avoiding paying a fair share of the costs of the transmission system. However, this does not mean that the Commission would not allow such services if voluntarily proposed by a transmission provider.

Finally, in response to American Forest & Paper, the transmission provider has every incentive to make non-firm service available to all eligible customers in order to benefit native load customers, as the revenues generated by this service are typically used as a revenue credit to offset the costs of providing firm service. In addition, parties may raise concerns with the Commission in a section 206 complaint if the transmission provider offers non-firm transmission service in a non-comparable, *i.e.*, unduly discriminatory fashion.

b. Amount of Designated Network Resources

In the Final Rule, the Commission indicated that it will not change the limitation on the amount of resources a network customer may designate. [393] The Commission explained that a transmission provider is required to designate its resources and is subject to the same limitations required of any other network customer.

The Commission further explained that limiting the amount of resources to those that the customer owns or commits to purchase will protect a utility from having to incur costs that are out of proportion to the customer's load.

With respect to the allocation of interface capacity under network service, the Commission clarified that a customer is not limited to a load ratio percentage of available transmission capacity at every interface. It explained that a customer may designate a single interface or any combination of interface capacity to serve its entire load, provided that the designation does not exceed its total load.

Rehearing Requests

A number of entities state that section 30.8 of the pro forma tariff should be clarified to conform to the Final Rule preamble. The preamble states that a network customer should not be limited to a load ratio percentage of available transmission capacity at every interface, but may designate a single interface or any combination of interface capacity to serve its entire load, provided that the designation does not exceed its total load. However, they point out that section 30.8 of the pro forma tariff provides that 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 ratio share.[394]

TAPS and Wisconsin Municipals ask the Commission to clarify the inconsistency by deleting the phrase ''Ratio Share'' at the end of the section 30.8. TAPS argues that section 30.8 of

[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.

the tariff conflicts with the preamble, other sections of the tariff itself (*see* section 28), and recent Commission orders (*Wisconsin Public Service Corporation,* 74 FERC ¶ 61,022 at 61,064 and *FMPA* v. *FPL,* 67 FERC 61,167 at 61,484). It further argues that load ratio restrictions on total interface usage would expand the market power of transmission providers.

EEI and Southern state that under section 30.8 and the related preamble language, it is unclear how the concept of load ratio share should be applied in the context of interface capacity, (*i.e.*, is the network customer entitled to a load ratio share of available transmission capacity or total transmission capacity for an interface?). They argue that ATC is the appropriate basis for calculating shares of interface capacity and state that the Commission should specify that network service entitles the user to a load ratio share of the available capacity of each interface. EEI adds that if sufficient interface capacity is available, a request by a network customer to use available interface capacity to bring in resources for network load in excess of its load ratio share of the interface should be accommodated under the point-to-point tariff and treated on a first-come, first-served basis.[395]

Florida Power Corp states that ''[i]n order to clarify that network customers may obtain transmission service over the transmission provider's interfaces in excess of their load ratio shares, the Commission should clarify that additional interface capability may be purchased (subject to availability) as firm point-to-point transmission service.'' (Florida Power Corp at 29).

Commission Conclusion

We agree that the pro forma tariff should be conformed to the preamble language in the Final Rule so that the interface capacity is limited to the customer's total load, not a load ratio share. This is consistent with the Commission's recent rehearing order in *FMPA* v. *FPL:*

We clarify that the phrase ''that is, up to its share of the load, 3%'' was not intended to limit FMPA's use of each interface to a discrete ratio (3%). Rather, FMPA, as well as Florida Power, can use each interface, if capacity is available, to service its entire network load. If the interface is [constrained] [sic], they will either pay redispatch costs or expansion costs based on their load ratio share.[396]

c. Eligibility Requirements

In the Final Rule, the Commission found that a non-discriminatory open access transmission tariff must be made available, at a minimum, to any entity that can request transmission services under section 211 and to foreign entities. [397]

Rehearing Requests

VT DPS and Valero state that the Final Rule does not appear to contemplate that marketers will buy network service or that one network service customer might serve a portion of the requirements of another network customer. Thus, they argue that network load can be double counted. To resolve this problem, they argue, service should be made available to suppliers rather than load, as provided in the NorAm NIS tariff, Section 1.5.

Commission Conclusion

Power marketers are specifically named in the definition of Eligible Customer (Section 1.11), and nothing in the Network Integration Transmission Service prohibits marketers from serving customers and designating those customers' loads (or portions thereof) as the marketers' Network Loads.

Additional rehearing requests regarding eligibility are addressed in Section IV.C.1. (Eligibility to Receive Non-discriminatory Open Access Transmission).

d. Two-Year Notice of Termination Provision

In the Final Rule, the Commission deleted the notice of termination provision from the tariff.[398]

Rehearing Requests

No requests for rehearing addressed this matter.

e. Termination of Service for Failure to Pay Bill

In the Final Rule, the Commission stated that section 7.3 of the Final Rule pro forma tariff provides that in the event of a customer default, the transmission provider may, in accordance with Commission policy, file and initiate a proceeding with the Commission to terminate service.[399]

Rehearing Requests

El Paso asserts that the Commission does not have the authority to prohibit a transmission provider from terminating service to a customer that has failed to pay its bill until permission from the Commission has been obtained. It argues that the Commission does not have abandonment authority under the FPA.

Commission Conclusion

El Paso is not correct. Under section 205 of the FPA, public utilities are allowed to effectuate changes in rates, charges, classification or service only after providing 60 days notice to the Commission and the public. Because a termination of service is clearly a change in service, public utilities must file notice of a termination 60 days prior to the proposed effective date.

In *Portland General Electric Company,* 75 FERC ¶ 61,310, *reh'g denied,* 77 FERC ¶ 61,171 (1996), we denied a requested waiver of section 35.15 of the Commission's Rules of Practice and Procedure to permit the utility to terminate service in the event of customer default. We indicated that we had previously explained the reasons for requiring public utilities to file notices of termination when seeking to discontinue service [400] and further explained that

electricity is not just any commercial good or service. Rather, Congress in the Federal Power Act has charged us with ensuring that sales for resale or transmission of electricity in interstate commerce by public utilities take place at rates, terms and conditions that are just and reasonable.[401]

f. Definition of Native Load Customers

The Commission defined the term ''Native Load Customers'' in section 1.19 of the pro forma tariff as:

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

Rehearing Requests

The pro forma tariff defines native load customers as ''[t]he wholesale and retail power customers of the Transmission Provider. * * *'' Cooperative Power argues that the definition of native load customers should recognize that joint planning is a sufficient criterion, and that construction and operation by the

[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.

transmission provider should not be necessary for native load status to be conferred. It asserts that under joint planning, the loads of transmission-only customers are considered native, therefore the Commission should eliminate the word power from the definition.[402]

NRECA and TDU Systems state that traditional wholesale customers that have long been on the system, have assisted in paying for past expansions, and will likely continue to be captive to a provider's monopoly transmission service, should have ''native load equivalent'' rights if they take network or long-term firm service. If the transmission provider has planned and will plan in the future for a customer's full or partial needs, they argue that the customer should be treated as the equivalent of native load. They point out that section 1.19 of the tariff limits native load status only to wholesale *power* customers of the transmission provider.

VA Com argues that the definition of native load in section 1.19 of the tariff should include existing distribution cooperatives and others who currently provide service to end users.

Commission Conclusion

We reject Cooperative Power's suggestion to include transmission-only point-to-point customers in the definition of native load. We note that network customers are provided with rights comparable to native load customers because the transmission provider includes their network resources and loads in its long-term planning horizon. However, a point-to-point transmission service customer is not similarly situated to native load and Network Customers. The Network service formula rate requires the Network customer to pay a load-ratio share of the costs of the transmission provider's transmission system on an ongoing basis, while a point-to-point transmission service customer is only responsible for paying on a contract demand basis over the contract term. The network customer and the native load of the transmission provider pay all the residual costs of the transmission system and face greater risks of rate fluctuations due to facility additions and variations in load of both its and other customers. In contrast, the point-to-point transmission service customer may be more transitory in nature electing shorter terms of service and specific forms of service tailored for discrete services over specific time periods that do not necessarily enter into the transmission provider's planning horizon. To the extent a transmission customer desires similar rights and cost responsibilities to a native load customer, it can always elect to take network service.

We further note that, in granting a right of first refusal to existing customers, we afforded existing transmission only point-to-point customers a priority to continue to use the transmission provider's system.

VA Com's proposed change to the definition of native load was made in conjunction with its proposed change in the reservation priority (highest priority for ''native load'', followed by firm contract customers and lastly, non-firm customers). Because we are rejecting VA Com's proposed reservation priority (*see* Section IV.G.3.a. above), we will also reject its proposed conforming change to the definition of native load as proposed by VA Com.

g. Off-System Sales

Regarding the unbundling of off-system sales, the Final Rule required that all bilateral economy energy coordination contracts executed before the effective date of Order No. 888 must be modified to require unbundling of any economy energy transaction occurring after December 31, 1996.[403] Concerning the treatment of revenues from transmission associated with off-system sales, the Commission stated in the Final Rule that revenue from non-firm services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates.[404]

Rehearing Requests

Montana Power asserts that the Commission should clarify that off-system sales that originate from generating plants or power purchases outside the transmission provider's system and do not use the transmission provider's transmission system should not be automatically assessed point-to-point charges.

Maine Public Service asks the Commission to clarify that revenues from off-system sales are not to be credited where the sales do not use the transmission provider's system (referencing sections 1.44 and 8.1 of the pro forma tariff). Maine Public Service states that it makes sales from Maine Yankee (which is not located on Maine Public Service's system) to customers not on its system and that it should not have to credit these sales revenues to its transmission customers.

Wisconsin Municipals asks the Commission to clarify that the provision and level of revenue credits are rate issues and that if parties have negotiated provisions for revenue credits, the Final Rule cannot be used to avoid obligations undertaken in a settlement.

Commission Conclusion

Utilities must take all transmission services for wholesale sales under new requirements contracts and new coordination services under the same tariff used by eligible customers. The Commission provided an extension until December 31, 1996, for utilities to take transmission service under the same tariff for their economy energy transactions, certain power pooling arrangements, and other multi-lateral arrangements.[405] The above criteria, however, only apply when a utility transmission system is being used to accommodate off-system sales. Therefore, a utility would not be required to take point-to-point transmission service if its transmission system is not being used for the transaction.

Maine Public Service's concern is misplaced. Maine Public Service states that certain of its sales do not use its own transmission system and that it pays other utilities for such transmission service. However, Section 8.1 only specifies the treatment of revenues the transmission provider receives from transmission service it provides itself when making third-party sales *using point-to-point transmission service under its tariff.* If Maine Public Service is not the transmission provider for these third-party sales, then Section 8.1 does not apply to such transactions.

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

h. Requirements Agreements

A detailed description of the Commission's unbundling requirements pertaining to requirements agreements is described below.

Rehearing Requests

Blue Ridge requests that the Commission clarify the definitions of requirements, economy and non-economy energy coordination agreements. In addition, Blue Ridge

[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.

[404] FERC Stats. & Regs. at 31,738; *mimeo* at 304.

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

seeks clarification regarding which dates are to be used to distinguish between existing and new contracts (July 11, 1994 or July 9, 1996).

Commission Conclusion

The definitions of economy and non-economy energy coordination agreements are addressed in section IV.F.4. (Bilateral Coordination Arrangements). With respect to Blue Ridge's concern regarding requirements agreements, we defined requirements contracts broadly in section 35.28(b)(1) of the Commission's regulations as ''any contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.'' The definition is intended to encompass partial requirements service, since that service is intended to meet the bundled load requirements of a customer that is not provided from other sources such as self-generation or unit power purchases. In contrast, a non-economy energy coordination agreement is not intended to meet, by itself, the entirety of a customer's bundled power requirement or the residual partial power requirement of a customer. For example, a 50 MW unit power purchase or a long-term firm power purchase would supply long-term firm power but a customer would likely need an additional partial requirements agreement to supply the residual amount of its load requirement.

Regarding Blue Ridge's request for clarification of the dates for new and existing agreements, the Commission explicitly stated in Order No. 888 that any bilateral wholesale coordination agreements executed after July 9, 1996 would be subject to the functional unbundling and open access requirements set forth in the Rule.[406] In addition, the Commission required that all bilateral economy energy coordination contracts executed on or before July 9, 1996 be modified to require unbundling of any economy energy *transaction* occurring after December 31, 1996. The Commission permitted all non-economy energy bilateral coordination agreements executed before July 9, 1996 to continue in effect subject to section 206 complaints.

For the purpose of distinguishing between existing and new wholesale requirements contracts and for stranded investment recovery provisions, the Commission established July 11, 1994 as the applicable date.[407] For a utility to recover stranded investment costs in new requirements contracts, it must include explicit provisions in the contract for stranded investment recovery. *Existing* requirements contracts would not need a similar provision to be eligible for stranded investment recovery.[408] Utilities are required to unbundle all *new* requirements contracts. The requirement that utilities unbundle *existing* wholesale requirements contracts is for informational purposes and will enable existing requirements customers to evaluate and compare the transmission component of existing contracts to alternative contracts prior to the existing contracts' expiration dates.

i. Use of Distribution Facilities

The Commission received requests for clarification regarding this issue which was not specifically addressed by the Commission in the Final Rule.

Rehearing Requests

CSW Operating Companies asks the Commission to make clear that to the extent a transmission provider makes available to transmission customers the use of distribution facilities, the terms governing the use of and the charges for such use should be set forth in the customer's service agreement.

Commission Conclusion

Utilities are free to include customer-specific terms and conditions or terms and conditions limited to certain customers (*e.g.*, a distribution charge) in a customer's service agreement and/or the network customer's network operating agreement.

j. Losses

The Commission received requests for clarification regarding this issue which was not specifically addressed by the Commission in the Final Rule.

Rehearing Requests

VT DPS asserts that network customers should not have to bear losses twice—the tariffs allow collection of losses over all network load, even that supplied by behind the meter generation. It argues that losses should only be paid on power actually transmitted over the company's system.

Commission Conclusion

The pro forma tariff neither specifies the applicable Real Power Loss factors (see tariff section 28.5) nor the demand levels to which the loss factors should be applied. Accordingly, concerns regarding the loss calculation for a customer should be raised when the transmission provider files with the Commission a service agreement for a network customer.

k. Modification of Non-Rate Terms and Conditions

The Commission's requirements pertaining to modification of non-rate terms and conditions is described below.

Rehearing Requests

TAPS asserts that the language of section 35.28(c)(1)(v) and the preamble of Order No. 888 are inconsistent. TAPS argues that the Commission should require a demonstration of consistency with and superiority to the terms and conditions of the pro forma tariff and indicate that it will not allow deviations that seek to withdraw the minimum terms and conditions of non-discriminatory transmission. According to TAPS, the Commission should also clarify that the Commission will not let onerous tariff terms creep in through the back door, *i.e.*, through service agreements. TAPS also maintains that the Commission should not allow transmission providers to use conformity as an excuse to evade commitments.

Commission Conclusion

Order No. 888 allows a utility the flexibility to propose, after the compliance tariffs go into effect, to modify non-rate terms and conditions of the tariff if it can ''demonstrate[] that such terms * * * are consistent with, or superior to, those in the compliance tariff.'' These are the same principles that are referenced in the regulation language (deviations allowed if the transmission provider can demonstrate the deviation is consistent with the principles of Order No. 888). While utilities are free to file revised tariffs after their compliance filings, any filing including service agreements will be carefully reviewed by the Commission to assure that the revised tariffs and service agreements are just and reasonable and consistent with the principles of Order No. 888.

With regard to TAPS' concern about transmission providers evading commitments, we reiterate that we will not require abrogation of existing contracts (and the commitments reflected therein) except on a case-specific basis.

l. Miscellaneous Tariff Modifications

(1) Ancillary Services

The Commission explained that the pro forma tariff incorporates conforming revisions consistent with the

[406] FERC Stats. & Regs. at 31,729–30; *mimeo* at 277–78.

[407] *Mimeo* at 769.

[408] FERC Stats. & Regs. at 33,110 and 31,804–05; *mimeo* at 85 and 497–98.

determinations discussed in the Final Rule.[409]

(2) Clarification of Accounting Issues

In the Final Rule, the Commission offered clarifications on the Final Rule pro forma tariff requirements and certain other accounting issues related to the Final Rule.[410]

(a) Transmission Provider's Use of Its System (Charging Yourself)

In the Final Rule, the Commission stated that the purpose of functional unbundling is to separate the transmission component of all new transactions occurring under the Final Rule pro forma tariff, thereby assisting in the verification of a transmission provider's compliance with the comparability requirement. With respect to off-system sales, the Commission stated that the transmission provider would book to operating revenue accounts those revenues received from the customer to whom it made the off-system sale.[411] The Commission required that the transmission service component and energy component of those revenues be recorded in separate subaccounts of Account 447, Sales for Resale.

Rehearing Requests

APPA argues that the revenue from the transmission component of *all* off-system uses must be included in the credit if comparability is to be achieved.

APPA also argues that booking revenue credits to Account 447 for a test year reduction does not ensure timely receipt by customers. It asserts that a monthly pass-through to all firm transmission customers is needed.

APPA further argues that a properly functioning revenue credit does away with the perception of disparate treatment of network and point-to-point customers. Similarly, TDU Systems argues that comparability requires that revenues attributable to transmission owners' use of their transmission systems be flowed through to customers' benefit immediately so that transmission owners and customers receive comparable price signals with regard to their uses of the system.

Commission Conclusion

The precise methodology to be used to credit revenues from off-system sales for the benefit of the tariff customers should be addressed in the compliance filing proceedings and will depend on the particular rate design methodology that is ultimately employed. APPA's proposed monthly pass-through of revenue credits raises potential issues including: (1) use of estimates versus actuals; (2) the appropriate time period to be utilized; and (3) firm versus non-firm distinctions. Accordingly, the issue of determining appropriate revenue credits is properly left for case-by-case determinations. However, we agree with APPA that revenue from the transmission component of all off-system uses of the transmission system (whether by the transmission provider or a transmission customer) must be treated on a comparable basis, whether through rate design or through revenue credits.

(b) Facilities and System Impact Studies

In the Final Rule, the Commission explained that comparability mandates that to the extent a transmission provider charges transmission customers for the costs of performing specific facilities studies or system impact studies related to a service request, the transmission provider also must separately record the costs associated with specific studies undertaken on behalf of its own native load customers, or, for example, for making an off-system sale.[412]

Rehearing Requests

No requests for rehearing addressed this matter.

(c) Ancillary Services

In the Final Rule, the Commission indicated that, at this time, it was not convinced that the amounts involved or the difficulty associated with measuring the cost of ancillary services warrants a departure from our present accounting requirements.[413]

Rehearing Requests

No requests for rehearing addressed this matter.

(3) Miscellaneous Clarifications

(a) Electronic Format

In the Final Rule, the Commission required that public utilities, in addition to complying with the requirements of Part 35, submit a complete electronic version of all transmission tariffs and service agreements in a word processor format, with the diskette labeled as to the format (including version) used, initially and each time changes are filed.[414]

Rehearing Requests

No requests for rehearing addressed this matter.

(b) Administrative Changes

In the Final Rule, the Commission set forth a number of tariff modifications that it indicated needed no further explanation.[415]

8. Specific Tariff Provisions

The Commission attached a pro forma tariff to the Final Rule as Appendix D. A number of entities have sought rehearing of various sections of that pro forma tariff. Their arguments and the Commission's responses are set forth below.

Rehearing Requests

Oklahoma G&E asks that the Commission add a definition for ''Interconnection'' that would be an interface where one or more points of delivery or points of receipt are located.

Commission Conclusion

We disagree with Oklahoma G&E that there is a need to add a definition for ''Interconnection'' to the Final Rule pro forma tariff. Oklahoma G&E has not supported its need for the proposed change and has failed to identify any potential problems that may result if its definition is not included.

Sections 1.12, 15.4 and 32.4

Rehearing Requests

Cajun argues that the Commission should mandate joint planning in the development of Facilities Studies. It alleges that a transmission provider's independent long-range plans frequently include longer, higher voltage facilities than are needed for the transmission customers' requirements. It further alleges that absent mandatory joint transmission planning, the transmission customers will always be paying for the incremental capacity cost of transmission enhancements that only fit into the Transmission Provider's independent long-range plans.

Commission Conclusion

A joint planning mandate as recommended by Cajun, NRECA and others is beyond the scope of this proceeding. However, the Commission encourages utilities to engage in joint planning with other utilities and customers and to allow affected customers to participate in facilities studies to the extent practicable. Moreover, on a regional basis, the Commission encourages the formation

[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.

of RTGs and ISOs to represent the needs of all participants in a region in the planning process.

Section 1.14

Rehearing Requests

CCEM asserts that the term Good Utility Practice is vague. It argues that the Commission should delete the reference to regional practices, but if it does not, the term should be clearly defined in each utility's tariff.

Commission Conclusion

The Commission recognizes that unique operating practices and conditions exist on a regional basis throughout the industry. Accordingly, the Commission permits certain deviations to the non-price terms and conditions of the tariff. In the Final Rule, we stated that any proposed modifications by the utility to the tariff to recognize regional operations and practices must be demonstrated to be reasonable, generally accepted in the region, and consistently adhered to by the transmission provider.[416]

Sections 1.22 and 1.25

Rehearing Requests

Blue Ridge requests clarification that a portion of a designated network resource need not consist of the entirety of a generating unit.

Commission Conclusion

Blue Ridge's request for clarification in the definition of ''Network Load'' in Tariff Section 1.22 and ''Network Resource'' in Tariff Section 1.25 is not necessary. Blue Ridge's concerns are based on the mistaken premise that a designated network resource must consist of the entirety of a generating unit. Tariff sections 1.25 and 30.1 explicitly specify that a network resource can be a *portion* of a generating resource or unit. Indeed, the Commission recently emphasized this point:

Ohio Cooperatives have disregarded the fact that a designated resource can be a part of a unit. In this example, Ohio Cooperatives would make two network designations for the 300 MW unit: a 100 MW designation for the 100 MW load on one system and a 200 MW designation for the 200 MW on the other system.[417]

Sections 1.25 and 30.1

Rehearing Requests

TDU Systems asserts that these sections should not be read to require assignment of specific Network Resources to specific control areas. They state that multiple control area network customers need to be able to dispatch their resources economically to serve their loads. They argue that the Commission would be in error to require that a transmission customer's resources be segmented if they are being dispatched to serve network load in one of several control areas and once so segmented, sales from such units be considered either third-party sales or become interruptible as to network load in a second control area and thus are not deemed Network Resources. They further argue that TDU systems with loads and resources in multiple control areas must be allowed to designate as Network Resources for each control area the totality of their resources which meet the owned or purchased requirements of section 1.25.

TDU Systems argues that these sections should be revised to include resources that are leased by a network customer on terms tantamount to ownership, or which, at a minimum, afford the network customer a first call right to that generating resource.

Commission Conclusion

TDU Systems' proposed revision to recognize leased resources appears reasonable and we revise these sections of the pro forma tariff, in relevant part, as follows (new text underlined, deleted text in brackets):

1.25 Network Resource: Any designated generating resource owned, [or] purchased *or leased* by a Network Customer under the Network Integration Transmission Service Tariff.

30.1 Designation of Network Resources: Network Resources shall include all generation owned, [or] purchased *or leased* by the Network Customer designated to serve Network Load under the Tariff.

Sections 1.33 and 1.34

Rehearing Requests

CCEM states that sections 1.33 and 1.34 should be changed to facilitate umbrella service agreements that include all points of receipt and delivery on a transmission provider's system.

Commission Conclusion

Consistent with our ruling in section IV.G.6 (Umbrella Service Agreement) regarding umbrella type service agreements for short-term firm point-to-point transmission service, we will modify sections 1.33 and 1.34 to require that Points of Receipt and Points of Delivery be specified in the service agreement for only Long-Term (more than one year) Firm Point-to-Point Transmission service.

Section 1.47

Rehearing Requests

Wisconsin Municipals asks the Commission to clarify that a utility is not prevented from including the load of interruptible customers in the denominator of the fraction used to perform the load ratio calculation. It claims that this is important in Wisconsin where the transmission system is planned without regard to the distinction between firm and interruptible power customers (interruptible customers are not subject to interruption for transmission reasons).

Commission Conclusion

The treatment of interruptible loads in the planning and operation of the Wisconsin transmission grid present a unique, case-specific situation that is best addressed on a case-by-case basis. As the Commission stated in the Final Rule:

all tariffs need not be ''cookie-cutter'' copies of the Final Rule tariff. Thus, under our new procedure, ultimately a tariff may go beyond the minimum elements in the Final Rule pro forma tariff or may account for regional, local, or system-specific factors. The tariffs that go into effect 60 days after publication of this Rule in the Federal Register will be identical to the Final Rule pro forma tariff; however, public utilities then will be free to file under section 205 to revise the tariffs, and customers will be free to pursue changes under section 206.[418]

Section 1.48

Rehearing Requests

Oklahoma G&E asks the Commission to clarify that the term ''Transmission Service'' as used in the pro forma tariff includes service provided on a network basis as well as on a point-to-point basis.

Commission Conclusion

The Commission used the term ''Transmission Service'' throughout the pro forma tariff to refer only to point-to-point service and not network service. We also note that the term ''transmission service'' (in lower case), which is also used throughout the pro

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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.

forma tariff, was used to refer to both point-to-point and network service. Oklahoma G&E has not identified any problems associated with our use of these terms and therefore has not supported its proposed modification.

Section 1.49

Rehearing Requests

Santa Clara and Redding state that the transmission system is defined as facilities owned, controlled or operated and that this could result in the same transmission facilities being the part of the transmission system of two entities (*e.g.*, COTP, which is owned by TANC, but operated by Western Area Power Administration (WAPA)). They ask the Commission to clarify that only one such entity should have the obligation to provide transmission service.

Commission Conclusion

This presents a fact-specific situation that is best addressed on a case-by-case basis. This situation would appear to arise for WAPA and TANC only if either utility receives a request for reciprocal transmission service or if either utility files a voluntary tariff. The appropriate entity to include the COTP facility in its transmission system for purposes of a transmission tariff may depend upon the circumstances of the transmission request. Therefore, a resolution of this question is appropriately deferred until such time as reciprocal service using the COTP facility is requested.

Section 3

Rehearing Requests

CCEM asks the Commission to clarify that a transmission customer may switch its supplier of ancillary services.

Commission Conclusion

The Final Rule requires that transmission customers obtain all necessary ancillary services for their transactions. They must purchase certain of these services from the transmission provider, but can self supply or obtain certain services from a third party. Consistent with these requirements, a transmission customer may switch suppliers of ancillary services not required to be provided by the transmission provider if it continues to demonstrate that it satisfies its ancillary service obligations.

Section 5.1

Rehearing Requests

ConEd points out that this section applies to Transmission Service, which the tariff defines to mean point-to-point service only. It requests that this section be clarified to include network service.

Commission Conclusion

The use of the term ''Transmission Service'' in section 5.1 of the pro forma tariff was an inadvertent error. We will change the term ''Transmission Service'' used in section 5.1 to ''transmission service'' so as to include both point-to-point and network transmission service.

Section 6

Rehearing Requests

CCEM asks the Commission to require that the text of the required sworn statement by non-transmission owning entities that they are not assisting an Eligible Customer be included in the tariff.

Commission Conclusion

We will deny CCEM's request as unnecessary. The Commission does not believe that it must mandate the precise text of the required sworn statement. Rather, the entity requesting transmission service properly has the burden of explaining in a sworn statement the circumstances of its service request, including on whose behalf it may be requesting service (for itself or for another party).

Section 8

Rehearing Requests

CCEM argues that, consistent with Commission policy for natural gas pipelines, transmission providers should be required to refund all ''penalties'' that are in excess of the costs incurred to balance transmitting system operations (citing Transco, 55 FERC ¶ 61,446 at 62,372 (1991) and TETCO, 62 FERC ¶ 61,015 at 61,117 (1993)).

Commission Conclusion

CCEM's argument is premature. Order No. 888 did not establish a rate or a penalty for Energy Imbalance Service. CCEM is free to raise this concern at such time as utilities file their proposed rates for Energy Imbalance Service.

Section 11

Rehearing Requests

CCEM contends that an unconditional and irrevocable letter of credit is extremely costly to obtain and could be used as subterfuge for discriminatorily denying service. CCEM argues that if an irrevocable letter of credit is used, a transmission provider should not be able to draw on it until it tenders a bill that has been improperly refused. (CCEM attached a proposed conditional letter of credit to its rehearing request). Several entities argue that a letter of credit should not be required for existing customers with a satisfactory credit history and should only apply to new customers or those with a history of payment delinquency.[419]

Commission Conclusion

While a transmission provider may require an unconditional and irrevocable letter of credit, if a customer believes that the transmission provider unreasonably rejected an alternative security proposal, it may seek relief through the dispute resolution procedures established in Tariff Section 12. Moreover, if a customer believes a transmission provider is attempting to use the unconditional and irrevocable letter of credit in an unduly discriminatory manner, it may file a complaint raising such concern in a section 206 filing.

Section 12

Rehearing Requests

According to Public Service Co of CO, the dispute resolution procedures: (1) Should allow a party to appeal an arbitration award on the basis that arbitrators have misinterpreted the requirements of the pro forma tariff and (2) where a utility is a member of an RTG, should allow the RTG dispute resolution procedures to be exclusive. Otherwise, Public Service Co of CO argues, entities may perceive that the Commission's procedures are more favorable than the RTG's and decide not to join. Moreover, it asserts that when a utility that is a member of an RTG has a dispute with a customer that is a non-member, the customer's forum should be the Commission, or the RTG's procedures if those procedures apply to non-members.

Dispute Resolution Associates asks the Commission to require that prior to submission of disputes for arbitration or Commission disposition, disputants should be required to pursue a mediated resolution with a qualified individual. If unsuccessful, it states that parties can elect arbitration or Commission disposition. If successful, it states that parties will have avoided litigation related costs and will not have jeopardized their ongoing business relationship. Dispute Resolution Associates also argues that representatives at all negotiating sessions should be authorized to enter into an agreement and asks that the Commission clarify that dispute resolution is one of the minimum requirements of the Final Rule. It also asks that the Commission require that any filed separate retail transmission

[419] *E.g.*, Santa Clara, Redding, TANC.

tariffs must include section 12 type dispute resolution procedures.

Commission Conclusion

Concerning the first issue raised by Public Service Co of CO, even if the arbitrator misinterprets the requirements of the pro forma tariff, the dispute resolution procedures require such decision (as it affects terms and conditions of service) to be filed with the Commission. Section 12.2 provides:

> The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

As to Public Service Co of CO's second concern, a utility's membership in an RTG with its own Dispute Resolution Procedures presents a fact specific situation to which a generic response is not appropriate. Whether both parties to a dispute are members of the RTG or only one of the parties is a member may have some bearing on which set of Dispute Resolution Procedures should apply.

Regarding Dispute Resolution Associates concerns, a utility is free to propose an initial process using ''mediated resolution with a qualified individual'' prior to using the Dispute Resolution Procedures. However, we see no need to modify the tariff to introduce such a proposed requirement as the Commission is not aware of other parties similarly claiming excessive costs or the threat of ''jeopardizing ongoing business relationship[s]'' due to the present Dispute Resolution Procedures. Finally, any attempts to delete the Dispute Resolution Procedures from any tariff on file with the Commission would require the transmission provider to demonstrate that its proposed modifications are consistent with or superior to the pro forma tariff terms and conditions.

Section 13.2

Rehearing Requests

CCEM asserts that the term ''reserved service'' should be changed to ''requested service.'' Utilities For Improved Transition and Florida Power Corp assert that the limitations on unconditional reservations are too stringent and that the Commission should modify the third sentence of section 13.2 to provide: ''If the Transmission System becomes oversubscribed, requests for longer-term service may preempt requests for shorter-term service up to a time period before the requested commencement of service that is equal to the requested term of service.''

Commission Conclusion

We will deny CCEM's request to replace the term ''reserved service'' in tariff section 13.2 with ''requested service.'' CCEM has not attempted to identify any uncertainties caused by the current wording of this section or explain any improvements that its proposed change would make.

Utilities For Improved Transition and Florida Power Corp's proposal to revise the deadline for when reservations for short-term firm transmission become unconditional is contrary to the Commission's intent in adopting the conditional reservation approach for short-term firm transmission and is rejected. Specifically, for service requests greater than a single day, week or month, Utilities For Improved Transition and Florida Power Corp's proposal decreases the period of time that such request is conditional; in other words, such request increases the unconditional reservation period, thus reducing the amount of longer-term transactions that the transmission provider can accommodate.

Sections 13.2 and 14.2

Rehearing Requests

CCEM notes that short-term firm point-to-point transmission service customers that have already reserved service have a right to match any longer-term requests for service before being preempted pursuant to section 13.2. However, CCEM states that these tariff sections do not establish a deadline for when such right must be exercised. Because the tariff established a conditional reservation period for short-term firm transmission service (during which time longer-term firm transmission requests can preempt shorter-term conditional reservations) CCEM suggests that a shorter-term firm transmission customer should be allowed to exercise its right to match longer-term service requests up until the end of the conditional reservation period. CCEM requests a similar clarification for non-firm transmission service but does not propose specific modification.

Commission Conclusion

While we agree with CCEM regarding the need to establish a deadline for exercising the right to match longer-term service requests for both short-term firm and non-firm transmission services, we will reject CCEM's proposed deadline for short-term firm transmission service. CCEM's proposed deadline would create market inefficiency by allowing the holder of the shorter-term firm transmission service an excessive amount of time to exercise its right to match the longer-term service. We feel that such a proposal could constitute a form of hoarding that would stifle the consummation of potential transactions and should not be allowed. CCEM's proposal would work to the detriment of any and all potential customer(s) requesting longer short-term firm transmission service. By allowing the original transmission customer to delay its response, the subsequent potential customer will be disadvantaged and may be required to make last minute alternative arrangements.

We believe that an especially quick response time is necessary for hourly non-firm transmission service customers to match longer-term service requests. Hourly non-firm transmission customers must exercise their right to match longer-term service requests immediately upon notification by the transmission provider of a longer-term competing request for non-firm transmission service. For non-firm transmission service other than hourly transactions and short-term firm transmission service, we believe a customer should exercise its right to match longer-term service requests as soon as practicable. The prompt exercising of such right is particularly critical where scheduling deadlines for such transactions are imminent. However, even for transactions with longer lead-times before service is to commence, we believe a response deadline of no more than 24 hours from being informed by the transmission provider of a longer-term competing request for transmission service is appropriate. Accordingly, the customer will be required to respond to the transmission provider as soon as practicable after notification of a longer-term request for service, but no longer than 24 hours from being notified or earlier if required to comply with the scheduling requirements for such services in tariff section 13.8 and 14.6. Tariff sections 13.2 and 14.2 will be modified accordingly.

Section 13.5

Rehearing Requests

Several utilities argue that section 13.5 is too broad because it also applies to costs that are included in rates on an embedded cost basis (which they claim can be evaluated when the transmission provider makes a rate filing).[420] They recommend that the Commission

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

modify the last sentence of the section as follows:

If redispatch costs or Network Upgrade costs are to be charged to the Transmission Customer on an incremental basis or costs relating to Direct Assignment Facilities that are to be charged to the Transmission Customer, the obligation of the customer to pay such costs shall be specified in the Service Agreement prior to the initiation of service.'' (Utilities For Improved Transition at 74–75).

Commission Conclusion

The Commission's intent in tariff section 13.5 was to require that any proposal to assess incremental charges to a customer must be specified in that customer's service agreement. Florida Power Corp and VEPCO correctly note that tariff section 13.5 inadvertently requires that *any* redispatch, network upgrade or direct assignment facilities, whether assessed on an incremental basis or included in embedded cost rates, must be specified in a customer's service agreement. To eliminate this unintended result, tariff section 13.5 is revised in relevant part as follows (new text underlined):

Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer *on an incremental basis* under the Tariff will be specified in the Service Agreement prior to initiating service.

Section 13.6

Rehearing Requests

CCEM asserts that the term ''Good Utility Practice'' should be deleted. CCEM claims that the inclusion of regional practices in Good Utility Practice makes the phrase vague and unpredictable. CCEM proposes that the Commission replace this phrase with a qualifier that pertains only to reliability and safety. According to PA Coops, equal priority places inordinate and unwarranted pressure on state siting and regulatory authorities to approve transmission projects required to provide service that may primarily benefit out of state parties. NYSEG argues that the Commission is not authorized to require curtailment of bundled retail service because it does not have jurisdiction over the rates, terms, and conditions of such service. It asserts that transactions subject to proportional curtailment should not include a transmitting utility's own use of its system to transmit its owned and purchased generation to native load customers as part of bundled retail service or services under rate schedules that are grandfathered. For transactions subject to proportional curtailment, NYSEG argues that allocation of curtailments will be comparable only if those multiple transactions being curtailed are of the same type of service and if each of the multiple transactions is for the same duration—these curtailments should be made on the same basis as required for non-firm PTP service. It asks the Commission to clarify that the curtailment requirements are not applicable to existing transmission contracts.

Commission Conclusion

CCEM's concerns center on the inclusion of the phrase regional practices in the definition of Good Utility Practice in section 1.14 of the pro forma tariff. These concerns are answered in section 1.14 above.

PA Coops' argument that long-term firm point-to-point transmission customers should be curtailed before network service customers and native load ignores the fact that the transmission provider has an obligation under the pro forma tariff to expand or upgrade its transmission system in response to requests for such long-term point-to-point transmission requests. In turn, such long-term firm point-to-point transmission customers undertake an obligation to pay for any transmission facility additions necessary for the provision of service pursuant to the tariff. Comparability requires that all long-term firm transmission customer be treated on a not unduly discriminatory basis in terms of curtailment priority.

Regarding NYSEG's arguments, the purpose of the curtailment provisions of the pro forma tariff is not to ''requir[e] curtailment of bundled retail service'' as NYSEG claims. Rather, the provision simply requires the transmission provider to curtail network and point-to-point transmission services on a basis comparable to the curtailment of the transmission provider's service to its native load. Indeed, we have repeatedly indicated that we do not have jurisdiction over bundled retail sales.

NYSEG's concerns regarding curtailment provisions in existing contracts are addressed above in Section IV.G.3.a. (Pro-rata Curtailment Provisions).

Section 13.7

Rehearing Requests

Utilities For Improved Transition and Florida Power Corp state that section 13.7 of the pro forma tariff makes it uneconomic to engage in system sales transactions on a firm basis because it requires the transmission provider to impose a separate charge for transmission from each generating station. They ask that the Commission clarify that if there is a sale from multiple generators, a reservation of transmission from each point of receipt will be required only in the amount of the expected relative contribution of each generating station to the energy that is sold. If it is not so clarified, they argue that the Commission should make one of the following modifications: (1) permit the customer to designate more than one generating station as a single point of receipt if it provides likely loadings of the units to the transmission provider; (2) provide that where the customer takes service from a group of generating stations on an economic dispatch basis, the reserved capacity is the sum of the reservations at the points of delivery (must also provide likely loadings); or (3) add a new subsection to Article 31 that provides that a network integration transmission customer may also reserve service on a contract demand basis for periods as short as one day (but do not reduce the one-year minimum term for load-based network service).

CSW Operating Companies asserts that the Commission should permit sales of power from multiple points of receipt, but such multiple generating units should be considered a single point of receipt. According to CSW Operating Companies, this provides maximum flexibility, lessens the need to establish secondary points of receipt, and is consistent with *FMPA* v. *FPL,* 74 FERC ¶ 61,006 at 61,014 (1996). They ask that the Commission revise section 13.7(b) to provide: ''The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. Such multiple generating units shall be considered a single Point of Receipt when the underlying sale is to be made on a system basis and not from specific generating units.'' (CSW Operating Companies at 10–11). TAPS requests that the Commission clarify that a network customer may make system sales to third parties using the point-to-point provisions without designating each generating resource as a point of receipt. Moreover, it asks that if the Commission intends to depart from *FMPA* v. *FPL,* that transmission providers be held to the same burden.

Commission Conclusion

Several utilities request rehearing on the tariff's requirement that sales of capacity and energy from multiple generating units must be designated as multiple points of receipt under point-to-point transmission service. These parties generally claim that this tariff requirement makes system sales transactions uneconomical and is contrary to the Commission's determination in *FMPA* v. *FPL,* 74 FERC ¶ 61,006 at 61,014 (1996).

As the Commission stated in the Final Rule:

all tariffs need not be ''cookie-cutter'' copies of the Final Rule tariff. Thus, under our new procedure, ultimately a tariff may go beyond the minimum elements in the Final Rule pro forma tariff or may account for regional, local, or system-specific factors. The tariffs that go into effect 60 days after publication of this Rule in the Federal Register will be identical to the Final Rule pro forma tariff; however, public utilities then will be free to file under section 205 to revise the tariffs, and customers will be free to pursue changes under section 206.[421]

Utilities that advocate modifying the pro forma tariff to accommodate system sales are free to file their specific proposals with the Commission in a section 205 filing.[422] Such proposals are best reviewed on a case-specific basis where the type of system sales engaged in by the transmission provider or transmission customer can be identified and described in detail. In order to ensure comparability, any proposed tariff modifications submitted in order to facilitate system sales of the transmission provider must also apply for sales by transmission customers as well.

Section 13.7(b)

Rehearing Requests

Blue Ridge argues that because units at the same geographic location can be connected to the system at different electrical locations, such as connections at different voltage levels (e.g., one unit connected at 500 kV and another unit connected at 230 kV), the Commission should replace the phrase ''at the same generating plant'' with ''at the same electrical location.'' (Blue Ridge at 23–24).

Commission Conclusion

Blue Ridge's proposed change is unsupported. The rationale supporting the need for such change and its intended result is unclear and unexplained and appears to be unnecessary and overly restrictive. Many generating units at a single plant are connected to the transmission grid at multiple voltages. Therefore, taking Blue Ridge's proposal to its logical end, a customer could face an additional charge at a single unit for every voltage level connection. In contrast, the intent of section 13.7(b) of the pro forma tariff is to treat multiple units at a single plant as a single point of receipt to avoid charging a customer an unnecessary additional charge.

Section 13.8

Rehearing Requests

CCEM asks the Commission to clarify that permissible scheduling changes extend to changes in the amount of power scheduled, the generation source, and delivery and receipt points. AMP-Ohio asserts that if the transmission provider can accommodate a change, the customer should be able to change its schedule less than 20 minutes before the hour or during the hour, and during an emergency or when the customer is attempting to remain within the 1.5% deviation band. It also asks the Commission to clarify that customers should be allowed to aggregate multiple points of delivery of less than a whole megawatt to be stated in whole megawatts (as is allowed for points of receipt). Otherwise, AMP-Ohio asserts, this would preclude small utilities from receiving service under a transmission provider's open access tariff.

Commission Conclusion

We agree with CCEM that permissible scheduling changes include the amount of power scheduled (up to the amount of capacity reservation stated in the customer's service agreement). However, a proposed modification to the generation source or to receipt and delivery points on a firm basis under the pro forma tariff is not simply a scheduling change, as maintained by CCEM, but is a new request for service, as set forth in pro forma tariff section 22.2.

AMP-Ohio's request regarding scheduling changes ignores the optional language in section 13.8 of the pro forma tariff, which permits a reasonable time limitation (other than the stated twenty minute deadline) that is ''generally accepted in the region and is consistently adhered to by the transmission provider.'' Accordingly, the pro forma tariff may be amended by the transmission provider to reflect the prevailing practice in the region.

AMP-Ohio's request regarding scheduling changes to allow the customer to stay within the deviation band of 1.5 percent may not be feasible depending upon the ramping rates of the particular generating units and may allow erratic scheduling by customers that could interfere with the transmission provider's ability to provide load following service.

AMP-Ohio's request for clarification that customers should be allowed to aggregate multiple points of delivery of less than a whole megawatt is unnecessary. Tariff section 17.2(viii) specifically allows customers to combine their requests for service for either points of receipt or points of delivery in order to satisfy the minimum transmission capacity requirement.

Section 14.2

Rehearing Requests

Tallahassee asks the Commission to clarify that a non-firm customer facing possible interruption for economic reasons will be allowed to match the duration and price of the surviving transaction and that once a non-firm transaction begins, it will not be preempted without whatever notice is sufficient and appropriate in the region, but the time period should be no shorter than 1–2 hours.

Commission Conclusion

The pro forma tariff does allow a customer to match a longer term reservation before being preempted. Moreover, non-firm transmission transactions, by definition, are interruptible for economic reasons (on a non-discriminatory basis) at any time. To the extent a prevailing regional practice exists regarding advance notice of interruption, the transmission provider may incorporate such a provision in its tariff.

Section 14.4

Rehearing Requests

CCEM asks the Commission to clarify that a non-firm point-to-point service agreement is an Umbrella Agreement and a non-firm point-to-point customer should be able to schedule a transaction at different primary and secondary receipt points and schedule changes in primary points with no filing requirement.

Commission Conclusion

The form of service agreement for non-firm transmission service is a non-transaction specific umbrella service agreement (*See* Attachment B to the pro forma tariff). Therefore, the service agreement does not require a specification of receipt and delivery points for non-firm point-to-point transmission service. However, we note that changes to the receipt or delivery points for non-firm transmission service other than those points reserved by the transmission customer in its service request are not ''schedule'' changes as claimed by CCEM, but will require the

[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).

submission of a new application for service pursuant to Tariff Section 18.

Section 14.6

Rehearing Requests

CCEM asks the Commission to clarify that ''scheduling changes'' for non-firm transmission include changes in the amounts scheduled, changes in receipt and delivery points, or changes in primary points.

Commission Conclusion

This issue is addressed in Section 13.8 above.

Sections 17, 18 and 29.2

Rehearing Requests

The EPRI/NERC Working Group (formerly the ''What and How Industry Working Group'') identifies certain areas in the pro forma tariff ''where the perceived scope of OASIS has grown beyond that which is feasible in Phase 1'' of OASIS. (EPRI/NERC Working Group at 2). EPRI/NERC Working Group references various information required in the application process under the pro forma tariff that is required to be submitted via OASIS to the transmission provider. EPRI/NERC Working Group explains that a substantial amount of information required under the pro forma tariff ''cannot be provided via the OASIS in Phase 1'' (*e.g.*, service agreements, requests for (A) non-firm point-to-point transmission service in the next hour, (B) multiple receipt and delivery points, (C) addition of new network loads or resources, loadflow and stability data).

The EPRI/NERC Working Group also claims that tariff section 17.1 creates confusion as it first requires that ''[a] request for Firm Point-To-Point Transmission Service * * * *must contain a written Application* * * *'' to the transmission provider, but then requires ''[a]ll Firm Point-To-Point Transmission Service requests should be *submitted by entering the information listed below on the Transmission Provider's OASIS*.'' (Emphasis added). The EPRI/NERC Working Group asserts that the above language confuses the process of an ''application for service agreement'' versus the process of ''a request for transmission service'' by a customer who already has a service agreement.

Commission Conclusion

The Commission recognizes that implementation of the OASIS is being accomplished in phases. In recognition of this fact, section 17.1 of the pro forma tariff provides:

> 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.

Moreover, we clarify that if Phase 1 of OASIS implementation does not support the submission of certain information over the OASIS, such information may be submitted by telephone or telefax (facsimile), as provided in the pro forma tariff, and promptly (within one hour) posted on OASIS by the Transmission Provider.[423]

Concerning the EPRI/NERC Working Group's apparent confusion regarding service application processes, we previously explained in Section IV.G.6 that the Commission is modifying the application process for firm point-to-point transmission transaction of less than one year (short-term firm transactions). The Commission will permit an ''umbrella service agreement'' approach where all of a customer's short-term firm transactions can be arranged under a single non-transaction specific umbrella service agreement rather than requiring a new service agreement for each short-term firm transaction. In contrast, service agreements for firm point-to-point transmission transactions of one year or more (long-term firm transactions) are transaction specific and require a separate service agreement for each transaction.

Section 17.1

Rehearing Requests

CCEM states that the 60 days in advance to request service should be shortened to 6 days. For service shorter than one year, it argues that the procedures should not be left to negotiation with a monopolist. For service greater than one month but less than one year, it asserts that a request should be submitted 3 days in advance; for weekly service, schedules should be submitted by some specific hour the day before service is to commence; and for hourly or daily service, schedules should be submitted no later than 20 minutes in advance.

Commission Conclusion

CCEM has provided no support for its proposal to shorten the lead time for requests for firm service from sixty days to six days. Sixty days in advance of the commencement of long-term (greater than one year) firm service is not an unreasonable time period. It provides transmission providers time to conduct security analyses, as well as perform system impact studies and facility studies that may be necessary. Accordingly, CCEM's request is denied.

Section 17.2

Rehearing Requests

CCEM argues that information concerning the location of the generating facility and the load ultimately served is not required in connection with a good faith request under the Policy Statement Regarding Good Faith Request for Transmission Services and should not be required in a Completed Application. However, if it is required, CCEM argues that it should remain confidential and not be disclosed. It further asks the Commission to clarify that a point-to-point customer can designate all receipt and delivery points in order to obtain umbrella-type service and can schedule receipt and delivery points as primary or secondary and can change primary points by filing another schedule.

Commission Conclusion

We will deny CCEM's proposed changes in part as unnecessary. The locations of generating facilities and loads are needed by the transmission provider to allow it to analyze whether the requested transmission service can be accommodated over the existing transmission system, as well as to plan upgrades and transmission facility additions.[424]

Tariff section 17.2 already requires that ''the transmission provider shall treat this [confidential] information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.''

With respect to CCEM's request to permit umbrella-type service, we note that we have adopted an umbrella-type service agreement approach for short-term firm transmission service, as

[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.

discussed in Section IV.G.6 (Umbrella Service Agreements).

Section 17.3

Rehearing Requests

CCEM asserts that a customer determined to be creditworthy should not have to submit a deposit for firm point-to-point transmission service. CCEM would limit this section to those customers found not to be creditworthy and asks the Commission to clarify that only the costs of system impact studies or facilities studies can be deducted from the deposit.

Commission Conclusion

Section 17.3 reflects a standard requirement in many existing tariffs and other agreements on file with this Commission. CCEM provides no compelling reason to revise this tariff provision.

We also deny CCEM's request regarding deductions from the deposit. We will not preclude a utility from demonstrating that it incurs costs other than system impact studies or facilities studies in processing a service application and arguing that these costs should be deducted from a deposit.

Section 17.4

Rehearing Requests

CCEM argues that a deficiency determination should be made in, at most, one day.

Commission Conclusion

CCEM provides no compelling reason to revise this tariff provision. CCEM's argument also ignores the fact that certain applications involve more complex unique transactions and associated arrangements which may require more time to review than other more standard applications. CCEM's apparent concern regarding deficient applications should be mitigated by the pro forma tariff requirement that the transmission provider must attempt to remedy minor deficiencies in the application informally with the transmission customer.

Section 17.5

Rehearing Requests

CCEM asserts that a transmission provider should respond to a completed application for firm transmission service within 10 minutes for hourly service, 10 minutes for daily service, 4 hours for weekly service, 1 day for monthly service, 2 days for service longer than one month but less than one year, and 5 days for service one year or longer.

Commission Conclusion

Section 17.5 requires the transmission provider to notify the eligible customer *as soon as practicable,* but no later than 30 days after receipt of a completed application if it can provide the service or if a system impact study will be required. We do not believe that further specificity in establishing deadlines for each type of service and duration of service is necessary. However, we are clarifying section 17.5 to require that all responses be made on a non-discriminatory basis. If CCEM believes the transmission provider is engaging in discriminatory behavior by delaying responses to service requests (or by responding to service requests by its wholesale merchant function more quickly than it responds to service requests by unaffiliated customers), it can file a section 206 complaint with the Commission.

Section 17.7

Rehearing Requests

Several utilities ask the Commission to clarify that, if transmission facilities have been constructed to accommodate a request for transmission service, delays by the customer in commencing service should be prohibited or the customer should pay the full carrying charges on the facilities during the period of delay (less any revenues received).[425] Similarly, EEI and Southern argue that if new facilities are constructed, but the customer postpones service by paying a reservation fee, fairness requires that the customer bear its cost responsibility for the new construction at the time the facilities are ready to be used.

Commission Conclusion

Because different factual circumstances could exist that may lead to alternative solutions to the problem, we will not adopt a generic resolution. Rather, the Commission believes it appropriate to allow each utility to propose solutions in subsequent section 205 filings with the Commission.

Section 19

Rehearing Requests

VA Com asks the Commission to clarify that determining the necessity of a transmission facility upgrade or addition remains a state prerogative. It asserts that native load customers may face reduced reliability, or may incur costs associated with premature additions, if calculations of ATC are incorrect. In addition, it asserts that generating facilities can also be used to relieve regional capacity constraints—''For example, a current proposal by Virginia Electric and Power Company (''Virginia Power'') seeks the Virginia Commission's approval of a major new transmission line. Virginia Power alleges that the line is needed since it would increase the availability of emergency off-system supplies and allow it to lower its capacity reserve requirements. If the Virginia Commission were to approve the line, it is conceivable that FERC could direct Virginia Power to use this additional interchange capability to facilitate wholesale wheeling transactions. In such an event, native load customers may be adversely affected since the utility would be forced to suffer diminished reliability or build additional generation or transmission facilities.'' (VA Com at 10–12). CCEM asks the Commission to require studies for short-term firm point-to-point service or requests for capacity that are posted on the OASIS.

Commission Conclusion

In the Final Rule, the Commission explicitly stated that

> public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon. However, any capacity that a public utility reserves for future growth, but is not currently needed, must be posted on the OASIS and made available to others through the capacity reassignment requirements, until such time as it is actually needed and used.[426]

This ability to reserve capacity to meet the reliability needs of native load would apply equally to transmission built in the future.

VA Com requested clarification of the intended treatment by the Commission in the ATC calculation of a transmission line built in lieu of generation for purposes of lowering reserve requirements for native load. If it seeks to withhold capacity in response to a request for service by an eligible customer, the transmission provider will have the burden of proof to demonstrate that any reserved capacity is needed for meeting native load and network customers' load growth or for purposes of meeting a reserve requirement level that is reasonable.

CCEM's request is unnecessary because system impact studies and facilities studies are required pursuant to tariff section 19 for both long-term and short-term firm point-to-point transmission service.

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

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

Sections 19.2 and 32.2

Rehearing Requests

Utilities For Improved Transition and VEPCO ask the Commission to modify these sections to require that a system impact study agreement specify the estimated charge instead of the maximum charge so that the transmission provider may collect all prudently incurred study costs.

Commission Conclusion

Utilities For Improved Transition and VEPCO correctly note that the use of the phrase ''maximum'' in the language of tariff sections 19.2 and 32.2 may prevent a utility from collecting the full costs of conducting a system impact study despite acting in a prudent manner. Accordingly, the relevant portion of these sections are modified as shown below to eliminate this potential inequity (deleted text in brackets):

(i) The System Impact Study Agreement will clearly specify [the maximum charge, based on] 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.

Sections 19.3 and 19.4

Rehearing Requests

TAPS asserts that the 15-day periods for customers to execute a service agreement after completion of a system impact study are too short and should be lengthened to 30 days or the transmission provider should be allowed to provide an extension for cause (with public notice) while the customer is pursuing an agreement in good faith.

Commission Conclusion

TAPS' proposed changes are not necessary because the eligible customer is provided a sufficient response time considering the situation to which the eligible customer is responding. Specifically, the 15-day period in section 19.3 refers to the situation where the transmission provider has conducted a system impact study and concluded that the requested service can be provided without the need to modify its transmission system. TAPS provides no reason why the eligible customer requesting the service should not be prepared to immediately accept the offer to provide service at the transmission provider's standard rate (without the need for upgrades, the eligible customer would not be assessed incremental transmission charges).

Similarly, the 15-day period in section 19.4 refers to the time in which the eligible customer has to execute a facilities study agreement in which it agrees to pay the transmission provider for the costs of conducting a facilities study. In contrast, when the facilities study is completed and the eligible customer is provided with a good faith estimate of any direct assignment facilities and/or share of any network upgrades, section 19.4 provides the eligible customer with 30 days to respond.

Section 22.1(d)

Rehearing Requests

Utilities For Improved Transition and Florida Power Corp ask the Commission to modify this section to require that a request for modification of service on a non-firm basis be made by submitting a modification to the original application with an OASIS posting. Otherwise, they assert, this section implies that such modifications would occur without using the transmission provider's OASIS.

Commission Conclusion

Utilities For Improved Transition and Florida Power Corp misinterpret this section of the tariff. The Commission's intention is simply to clarify that the customer's request to modify its firm transmission service to receive service over secondary receipt and delivery points on a non-firm basis would not require a separate application for *non-firm transmission service.* The concerns expressed with respect to posting on the OASIS are addressed in Order No. 889–A.

Section 23.1

Rehearing Requests

CCEM asserts that the Commission sHhould specify the filings necessary for assignment of service referenced in this section or delete the clause. In addition, CCEM asks the Commission to clarify that the identical services will be provided at no additional cost to the assignee or the reseller.

Commission Conclusion

The pro forma tariff is a tariff of general applicability. For administrative reasons, the listing of every conceivable situation in which an assignment or transfer of service from one entity to another may require a separate filing is not feasible. For example, if the Commission lists only a single situation that requires a separate filing and subsequently determines another situation would also require a filing, all of the pro forma tariffs on file with the Commission would need to be revised to reflect the change.

CCEM's request that the Commission clarify that reassigned services will be provided at no extra cost is also denied. CCEM ignores the fact that nothing in the pro forma tariff prevents the transmission provider from seeking a change in rates pursuant to a section 205 filing whether such filing relates to a general increase in rates to all transmission customers or to additional costs the transmission provider asserts it incurs due to providing service to an assignee. As always, the transmission provider bears the burden of proof of demonstrating that its proposal is just and reasonable.

Section 23.2

Rehearing Requests

CCEM asks the Commission whether an assignee can change primary points if there is only a partial assignment.

Commission Conclusion

Whether the assignment is full or partial is immaterial. If an assignee wishes to change its receipt or delivery points on a firm basis (full or partial), the request will be treated as a new request for service as required under tariff sections 22.1 and 23.1. However, if an assignee wishes to change receipt or delivery points on a non-firm (full or partial) basis, such change can be accomplished without the need for a new service agreement as provided in pro forma tariff section 22.1.

Sections 25 and 34

Rehearing Requests

VT DPS asks the Commission to revise these sections to state that ''all firm customers should share in non-firm revenues'' consistent with the language of the preamble.

Commission Conclusion

VT DPS' request is denied. The Commission did not intend to mandate the rate methodology used to reflect any cost reductions that may be associated with the provision of non-firm transmission service. While the Commission would generally expect all firm customers to share in non-firm revenues, the use of revenue credits is not the only acceptable method of reflecting non-firm system usage. The transmission provider's method of reflecting revenues from non-firm service should be addressed on a case-by-case basis.

Section 29.1

Rehearing Requests

TAPS contends that, to avoid improper use of operating agreements by transmission providers, the

Commission should either permit network operating agreements to be filed in unexecuted form or include a network operating agreement as part of the pro forma tariff.

Commission Conclusion

The network operating agreement is expected to be a highly detailed agreement between the transmission provider and network customer that establishes the integration of the network customer within the transmission provider's transmission system. Due to the unique characteristics of network customers' systems and the level of customer-specific information and arrangements required under a network operating agreement, it is likely that each network operating agreement will be different for each customer. Accordingly, the Commission does not believe it appropriate to mandate a particular form of network operating agreement for inclusion in the pro forma tariff. However, if a transmission provider wishes to include a generic form of network operating agreement in its pro forma tariff (to be modified as required and as mutually agreed to on a customer-specific basis), it may propose to do so in a section 205 filing or it may file an unexecuted network operating agreement in a section 205 filing.

To the extent a customer believes a transmission provider is engaging in unduly discriminatory practices via the network operating agreement, the customer may file a section 206 complaint with the Commission.

Section 29.4

Rehearing Requests

TDU Systems asserts that this section does not identify who should determine what facilities are ''necessary to reliably deliver capacity and energy. * * *'' It asks the Commission to clarify that this is solely the responsibility of the transmission customer.

Commission Conclusion

TDU Systems' argument ignores tariff section 35.1, which specifies:

[t]he Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice *and in conformance with the Network Operating Agreement.* (emphasis added)

Accordingly, the determination of what network customer facilities are ''necessary to reliably deliver capacity and energy * * *'' is to be agreed upon by both the transmission provider and network customer and specified in the network operating agreement. To the extent the parties do not agree, the transmission provider will file an unexecuted network operating agreement with the Commission and we will resolve the dispute.

Section 30.1

Rehearing Requests

VT DPS argues that, consistent with section 30.7, section 30.1 should not require that a network resource be available on a strictly non-interruptible basis.

Commission Conclusion

VT DPS' request is denied. The Commission believes that a network customer should only be allowed to designate non-interruptible network resources. To allow otherwise would interfere with the planning process as well as the day-to-day operation of the transmission system to integrate resources with customer's loads (*e.g.*, the transmission provider will be unable to plan for what generation resource will be available to meet a customer's load in the event its designated resource is subject to interruption). Similarly, for operational purposes on a day-to-day basis, an interruption of a network customer's designated resource could cause a transmission constraint.[427] Because constraints affecting reliability may lead to curtailment or redispatch of all network resources, other network customers would be affected by such interruptions on a load-ratio basis. However, to the extent a network customer wishes to use an interruptible generation source, it can still use this generation source on an as-available basis to import energy to serve its load pursuant to pro forma tariff section 28.4.

Section 30.4

Rehearing Requests

PA Coops ask the Commission to modify this section ''to permit the Network Resources to be operated at outputs that exceed the Network Customer's designated Network Load plus losses when the Network Resource's output is being sold to a third party or the Network Resource is called upon to be operated by the Network Customer's power pool, ISO or control area operator.'' (PA Coops at 8–9). Similarly, Santa Clara and Redding ask the Commission to modify the last sentence to state: ''* * * exceeds its designated Network Load, plus non-firm sales delivered under Part II, plus losses'' so that network resources will not remain idle when they could otherwise generate non-firm power and energy for sale at competitive prices.

In addition, TDU Systems argues that the arbitrary limits on the ability of network customers to operate Network Resources prevents economic dispatch or the use of resources to meet load requirements and limits the ability to schedule the output of Network Resources between and among control areas, effectively preventing the network customer from operating an integrated system.[428] TDU Systems asserts that the Commission should not presume that a network customer's economic dispatch will burden a transmission provider, but should require a transmission provider to demonstrate that such a burden will occur. TAPS asks the Commission to clarify this section so as to bar not the operation of network resources in excess of network load, but rather the usage of network service in connection with operation of such resources in excess of network load. TAPS adds that section 30.4 is contrary to *FMPA* v. *FPL,* 74 FERC at 61,014–15. AEC & SMEPA argues that the Commission should provide the necessary latitude for such resources to be used across multiple control areas to service the total load of transmission users.

Commission Conclusion

Preliminarily, TDU Systems and others' argument that a designated network resource must consist of the entirety of a generating unit is mistaken, as we explained in sections 1.22 and 1.25 above. The Commission's intent in requiring that the output of network resources not exceed network load plus losses is to prevent designated network resources from being used to make firm sales to third parties. This is consistent with the pro forma tariff's requirement in sections 1.25 and 30.1 that:

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.

Absent a requirement that network resources always be available to meet a customer's network loads, reliability of service to the network customer as well as to native load and other network customers could be affected, as we describe in detail in section 30.1 above. If a network customer desires to enter into a firm sale from its designated network resources or use such network resources for meeting reserve requirements, it must eliminate the appropriate resources or portions thereof from its designated network

[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.

resources pursuant to pro forma tariff section 30.

Santa Clara, Redding and others contend that this limitation improperly restricts the use of network resources for non-firm sales. It was not the Commission's intent to prohibit the network customer from engaging in non-firm sales from idle designated network resources. We find that the non-firm operation of network resources will not affect the availability of such resources on a firm basis because such non-firm uses are subject to interruption. Accordingly, the Commission's concerns regarding the reliable provision of network service are satisfied.

Furthermore, as noted by Pennsylvania Coops, emergencies could arise in which the transmission provider may request that a network customer alter the operation of its network resources in response to a contingency, which action could result in a violation of the limitation in section 30.4. Therefore, the Commission believes an exception to the network resources output limitation is also appropriate for such emergency situations. Accordingly, tariff section 30.4 is revised, in relevant part, consistent with the above findings, as shown below (emphasis added):

> 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 its Transmission System.*

The remaining concerns expressed by TDU Systems with respect to the economical operation of a network customer's loads and resources located in multiple control areas are addressed above in Section IV.G.1.b. (Network and Point-to-Point Customers' Uses of the System (so-called ''Headroom'')).

Section 30.6

Rehearing Requests

CSW Operating Companies asks the Commission to clarify that a customer has the obligation to replace the loss of a resource that is not physically interconnected with the transmission provider's transmission system within the time that is customary in the region or be subject to curtailment and suggests language to be included as section 33.8. CSW Operating Companies indicates that it intends to include a provision addressing this issue in the form of a network operating agreement included in the individual companies' Final Rule compliance tariffs.

Commission Conclusion

The Commission agrees with CSW Operating Companies that the appropriate place to address detailed operational requirements such as this is the Network Operating Agreement. If disputes arise, they can be addressed on a case-by-case basis.

Section 30.7

Rehearing Requests

Wisconsin Municipals asks the Commission to clarify that, for purposes of comparability between network and point-to-point customers, a customer may not reserve capacity for firm point-to-point transmission service until the customer can show that it owns or has committed to purchase generation under an executed contract that it intends to use over the reserved transmission contract path. Wisconsin Municipals claims that without the requirement to demonstrate ownership or contractual rights to the output of a generation resource, the point-to-point customers will have the advantage over network customers of being able to reserve transmission service over facilities with limited available transmission capacity earlier than network customers. Wisconsin Municipals also argues, in essence, that a single or a few point-to-point customers would be able to engage in hoarding of transmission capacity by reserving all available transmission capacity over certain transmission facilities.

Commission Conclusion

The arguments presented by Wisconsin Municipals in support of its proposal are misplaced. Wisconsin Municipals' assertion that point-to-point customers would be able to reserve transmission service over facilities with limited available transmission capacity earlier than network customers overlooks the fact that the Final Rule allows transmission providers to reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the transmission provider's current planning horizon.[429] Wisconsin Municipals' concerns regarding hoarding of transmission capacity are answered in Section IV.C.6. (Capacity Reassignment). Finally, Wisconsin Municipals' argument that comparability requires that both network and point-to-point customers be required to demonstrate ownership or contractual rights to the output of a generation resource is not persuasive. Network and firm point-to-point transmission service are different services. Firm point-to-point transmission service is available for periods as short as one day, whereas network service is designed to accommodate a longer term of service with a minimum term of service of one year. The requirement to demonstrate ownership or contractual rights to generation for network service is necessary because the transmission provider must be able to serve the network load from any of the designated resources. In contrast, point-to-point service is a capacity reservation service between specified points of receipt and points of delivery. Accordingly, this network requirement does not need to be extended to firm point-to-point service under the guise of comparability.

Section 31.2

Rehearing Requests

TDU Systems asks the Commission to clarify that an application for new network load for an existing network customer need only address the additional network service needed to serve the new Network Load and does not in any way implicate the existing network service for which the network customer has already contracted.

Commission Conclusion

No clarification is necessary. Tariff section 31.2 explicitly states in relevant part:

> A designation of new Network Load must be made through a *modification of service* pursuant to a new Application. (Emphasis added)

Section 32.3

Rehearing Requests

TDU Systems asserts that this section requires too short a time for customers to evaluate a system impact study. It argues that, at a minimum, customers should have 60 days to evaluate a study and, in the event of a dispute, the application should remain viable until the dispute is resolved (also argues that the time periods set forth in sections 19.1, 19.4, 32.1, 32.3 and 32.4 are too short).

Commission Conclusion

TDU Systems' proposed changes are not necessary as the pro forma tariff provides an eligible customer sufficient time to respond to a system impact

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

study. Specifically, the 15-day period in section 32.3 refers to a situation where the transmission provider has conducted a system impact study and concluded that the requested service can be provided *without* the need to modify its transmission system. TDU Systems provides no reason why the eligible customer should not be prepared to immediately accept the offer of providing service at the transmission provider's standard rate (without the need for upgrades, the eligible customer would not be assessed incremental transmission charges).

Similarly, the 15 day period in sections 19.1, 19.4, 32.1 and 32.4 refer to the time in which the eligible customer has to agree to execute an agreement to pay the transmission provider for costs of conducting studies (a system impact study in sections 19.1 and 32.1 and a facilities study in sections 19.4 and 32.4). TDU Systems provides no reason why it should not be prepared to accept or reject the relatively minor costs of further studies to determine whether its requested transmission service can be accommodated by the transmission provider.

In contrast, when the facilities study is completed and the eligible customer is provided with a good faith estimate of any direct assignment facilities and/or share of any network upgrades, the eligible customer is given 30 days to respond, which is more than a sufficient time.

Sections 33.2 and 34.4

Rehearing Requests

TAPS asserts that the Commission cannot shunt aside the need for ongoing revenue crediting to reduce transmission charges as a rate issue, while allowing monthly redispatch costs to be collected monthly in charges under the tariff. It contends that the Commission must require revenues to be shared on an ongoing, load-ratio basis.

Commission Conclusion

As discussed above, redispatch of all Network Resources and the transmission provider's own resources is only to be performed to maintain the reliability of the transmission system, not for economic reasons. As a result, the frequency of redispatch charges being assessed to network customers is expected to be infrequent. In addition, the Commission is according substantial flexibility to public utilities to propose appropriate pricing terms in their compliance tariff, which includes the treatment of revenue credits. As mentioned above, there are several methods that utilities can use to properly reflect a benefit from non-firm transmission service to firm transmission customers. We do not believe it appropriate to mandate a specific method, such as automatic monthly flow through of revenue credits, at this time. However, TAPS may pursue this issue when utilities file their compliance rates or subsequent 205 rate filings.

Section 34.3

Rehearing Requests

Several utilities assert that because the monthly transmission system load is composed in part of the contract demands of all firm point-to-point transmission customers and under the Rule the charge for firm point-to-point service may be derived by dividing the transmission cost of service by the sum of the transmission provider's 12 monthly peak firm transmission loads, the transmission provider is prevented from recovering its entire cost of service.[430]

Maine Public Service states that parties should be allowed to argue on a case-by-case basis that firm transmission revenues should be credited instead of including the demands in the denominator (it indicates that this issue is pending in Docket No. ER95–836). It asserts that the revenue credit method would prevent transmission providers that offered discounts from unjustly being penalized for that decision and is the only method that permits utilities to have an opportunity to recover their costs. It adds that the Commission established procedures to keep gas pipelines whole in this same situation.

Commission Conclusion

While the Commission established one method of calculating load ratios and allocating costs in Order No. 888,[431] utilities are free to propose alternative pricing methodologies in a section 205 filing consistent with the Commission's Transmission Pricing Policy Statement.[432] We note, however, such utilities will have the burden of demonstrating that these methods would not result in over-collections of their revenue requirement.

[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.

[432] *See* FERC Stats. & Regs. at 31,768–70; *mimeo* at 394–99.

Section 34.4

Rehearing Requests

TDU Systems asks the Commission to clarify, as a matter of comparability, that any mechanism proposed by a transmission provider to collect charges based on opportunity costs associated with redispatch must provide for the collection of other customers' like costs and payments to those customers.

Commission Conclusion

This issue is addressed in Section IV.G.1.e. (Opportunity Cost Pricing).

Schedules 7 and 8

Rehearing Requests

TAPS asks the Commission to clarify that these schedules do not approve ''heightened'' charges for short-term services.

Commission Conclusion

The Commission did not specify transmission rates for any tariff services in Order No. 888. The rates for long-term firm transmission, short-term firm transmission and non-firm transmission services are to be proposed by the transmission provider, as listed on Tariff schedules 7 and 8, and filed with the Commission. TAPS' argument regarding ''heightened'' charges for these services is therefore premature. TAPS is free to raise this concern at such time as utilities file their proposed transmission rates.

Attachment G

Rehearing Requests

Santa Clara and Redding ask the Commission to modify Attachment G so that, where interconnection/operational standards are in place and working effectively, additional standards are not imposed simply as a result of switching to the pro forma tariff from its current interconnection service.

Commission Conclusion

The pro forma tariff does not specifically require that the network operating agreement between the transmission provider and network customer must be a new agreement. However, the network operating agreement is expected to be a highly detailed agreement between the transmission provider and network customer establishing the integration of the network customer within the transmission provider's transmission system. Existing agreements between the customer and transmission provider may not provide all of the information required or make all of the technical arrangements required under the pro forma tariff (*e.g.,* redispatch and ancillary services information and arrangements.) Nevertheless, to the extent the transmission customer is currently receiving network integration transmission service or similar service and its present interconnection agreement fully comports with the requirements of the terms and conditions of the tariff including the informational requirements specified in tariff sections 33 and 35, then the present interconnection/operations agreement can be substituted for a network operating agreement or modified appropriately.

9. Miscellaneous Tariff Administrative Changes

Due to administrative oversight, certain tariff sections require minor corrections or modifications. Because of the administrative nature of these changes, we believe that no further discussion is needed.

Section 12.1 Internal Dispute Resolution Procedures

—Changes ''Transmission Service'' to ''transmission service''

Section 13.6 Curtailment of Firm Transmission Service

—Changes the description regarding curtailment of multiple transactions to:

the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers.

10. Pro Forma Tariff Compliance Filings

Absent a waiver, all public utilities must submit, no later than July 14, 1997, a compliance filing that reflects the tariff changes set forth in this order on rehearing.[433]

A conforming pro forma tariff, containing all the revisions and clarifications contained in this order on rehearing, is attached as Appendix B. In addition, an electronic version of the conforming pro forma tariff will be made available on the Commission's electronic bulletin board service (Commission Issuance Posting System (CIPS)) in redline/strikeout form in WordPerfect 5.1 format.

H. Implementation

In the Final Rule, the Commission set forth the details of the implementation procedures and included special implementation requirements for coordination arrangements (power pools, public utility holding companies, and bilateral coordination arrangements).[434]

The Revised Procedures

The Commission adopted slightly different implementation procedures for Group 1 public utilities (tendered for filing open access tariffs before the date of issuance of the Rule) and for Group 2 public utilities (did not tender for filing open access tariffs before the date of issuance of the Rule).

1. Group 1 Public Utilities

In the Final Rule, the Commission required Group 1 public utilities, within 60 days following publication of the Final Rule in the Federal Register, to make section 206 compliance filings that contain the non-rate terms and conditions set forth in the Final Rule pro forma tariff and identify any terms and conditions that reflect regional practices, as discussed below.[435]

As to rates, the Commission noted that a transmission tariff rate is already in effect for all Group 1 public utilities, except for the few with recently-tendered applications that have not yet been accepted for filing.

The Commission noted, however, that if a Group 1 public utility determined that certain rate changes are necessitated by the revised non-rate terms and conditions, it may file a new rate proposal under FPA section 205. The Commission indicated that such filings must be ''conforming'' [436] under the Transmission Pricing Policy Statement and must be made no later than 60 days after publication of the Final Rule in the Federal Register and intervenors may raise any concerns with the filings within 15 days after such filings. [437] The Commission imposed a blanket suspension for any filings by Group 1 public utilities proposing rate changes necessitated by the new non-rate terms and conditions. The Commission further indicated that these rates will go into effect, subject to refund, 60 days after publication of this Rule in the Federal Register (the same day on which the non-rate terms and conditions of the Final Rule pro forma tariff go into effect).

2. Group 2 Public Utilities

In the Final Rule, the Commission indicated that Group 2 public utilities will be treated the same as Group 1 public utilities with regard to non-rate terms and conditions, but will be treated slightly differently from Group 1 as to rates, since Group 2 utilities have not filed any proposed rates.[438] The Commission required these utilities to *either:* (i) within 60 days following publication of the Final Rule in the Federal Register, make section 206 compliance filings that contain the non-rate terms and conditions set forth in the Final Rule pro forma tariff and identify any terms and conditions that reflect regional practices, as discussed below; and (ii) within 60 days following publication of the Final Rule in the Federal Register, make section 205 filings to propose rates for the services provided for in the tariff, including ancillary services; *or* (iii) make a ''good faith'' request for waiver. The Commission added that the rates must meet the standards for conforming proposals in the Commission's Transmission Pricing Policy Statement and comply with the guidance concerning ancillary services set forth in this order.

The Commission explained that intervenors may raise any concerns with these filings within 15 days after the filing.[439] The Commission imposed a blanket suspension for all such rate filings and indicated that they will go into effect, subject to refund, 60 days after the publication of this Rule in the Federal Register (the same day on which the terms and conditions of the compliance tariffs go into effect).

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[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.

[437] 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.

3. Clarification Regarding Terms and Conditions Reflecting Regional Practices

In the Final Rule, the Commission explained that it had built a degree of flexibility into the tariffs to accommodate regional and other differences. [440] It explained that certain non-rate Final Rule pro forma tariff provisions specifically allow utilities either to follow the terms of the provision or to use alternatives that are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider (*e.g.*, time deadlines for scheduling changes, time deadlines for determining available capacity). In addition, it explained that other tariff provisions require utilities to follow Good Utility Practice (section 1.14 of the Final Rule pro forma tariff).

4. Future Filings

In the Final Rule, the Commission indicated that once the compliance tariff and conforming rates go into effect, which would be 60 days after publication of the Rule in the Federal Register, a public utility (either Group 1 or Group 2) may file pursuant to section 205 a tariff with terms and conditions that differ from those set forth in this Rule, provided that, among other things, it demonstrates that such terms and conditions are consistent with, or superior to, those in the compliance tariff.[441] However, the Commission emphasized that the public utility may not seek to litigate fundamental terms and conditions set forth in the Final Rule. In addition, the Commission explained that the public utility may file whatever rates it believes are appropriate, consistent with the Transmission Pricing Policy Statement.

5. Waiver

In the Final Rule, the Commission found that it is reasonable to permit certain public utilities for good cause shown to file, within 60 days after the Rule is published in the Federal Register, requests for waiver from some or all of the requirements of this Rule.[442] The Commission explained that the filing of a request in good faith for a waiver from the requirement to file an open access tariff will eliminate the requirement that such public utility make a compliance filing unless thereafter ordered by the Commission to do so. The Commission emphasized, however, that it will not exempt such public utility from providing, upon request, transmission services consistent with the requirements of the Final Rule.

Rehearing Requests

Wisconsin Municipals asserts that the Commission should ''require utilities (if requested by their customers) to honor the settlements to which they have agreed and to file the *pro forma* tariff, modified to incorporate settlement provisions that exceed the minimum provisions of the *pro forma* tariff, as their implementational filing.'' Alternatively, it asks that the Commission ''require parties with settlements to make a Section 205 filing one day following their implementation filing, change any rates, terms and conditions in the *pro forma* tariff as necessary to incorporate any superior provisions from their settlement tariffs into the *pro forma* tariff, and seek any waivers necessary to make the settlement tariff effective immediately.'' (Wisconsin Municipals at 7–10).

Blue Ridge requests rehearing of the ''unbalanced tariff implementation process that rolls over the due process rights of transmission customers.'' It asserts that utilities should not have the right to file a '''Good Utility Practices,' blank check variance for regional practices in the compliance docket.'' (Blue Ridge at 33–35). Blue Ridge further requests that Group 1 utilities file compliance tariffs in the same docket as their pending open access dockets and asks that subsequent changes be in a separate docket as a new general rate case. Blue Ridge also states that the Commission should explicitly mention that customers have the right to file section 206 requests to change the tariffs.

Indianapolis P&L argues that the pricing requirements are unjust, unreasonable, unlawful, confiscatory and an abuse of discretion as to Indianapolis P&L. It asserts that its rates are not based on embedded, original cost, but, as a matter of Indiana law, its utility property is valued at the ''fair value,'' which exceeds the embedded original cost of such property. It declares that it is impossible for Indianapolis P&L to comply with both the comparability requirement and the requirement that transmission rates be based on original cost. It states that the requirement to provide transmission service and generation-based ancillary services at rates based on original cost is not comparable to Indianapolis P&L's own use of its assets. Accordingly, it argues that the Commission should allow Indianapolis P&L to set its initial open access rates on a fair value, long-run marginal cost basis. Alternatively, it states that the Commission could grant Indianapolis P&L a waiver from the requirements of the Open Access Rule.

Indianapolis P&L further argues that the imposition of an obligation to enlarge generation to provide ancillary services is beyond the Commission's statutory authority. It explains that Indianapolis P&L is an incidental transmission owner and a relatively small public utility and asks that the Commission grant it waiver from the requirements of open access and OASIS. In deciding whether to grant a waiver, it asserts that the Commission should also consider system size and configuration, the amount of wholesale revenues or MWH sales, or the availability of competing transmission paths.

Union Electric argues that the final rules violate procedural due process and that the implementation schedule is unrealistically ambitious. It argues that where the final rules call for changes from the NOPRs that could not be reasonably anticipated, they amount to deprivation of due process and rights to fairness in the administrative process. Indeed, it points out, the Commission itself has not even completed its promulgation of the OASIS Final Rule. Union Electric is concerned that it has not had an adequate time to comply with and comment on the rules.

Commission Conclusion

Wisconsin Municipals has misinterpreted the Commission's findings in Order No. 888, and thus its concerns are without merit. While it is true that Order No. 888 requires all public utilities to make compliance filings containing the non-price terms and conditions set forth in the Final Rule pro forma tariff,[443] Order No. 888 also states that ''we are not abrogating existing requirements and transmission contracts generically. * * *'' [444] In short, the Commission is not requiring (or even generically allowing) the abrogation of existing transmission contracts, but is only requiring that jurisdictional transmission providers must also offer transmission service under the Final Rule pro forma tariff *in addition to* whatever commitments the provider will continue to have under its existing contracts. [445]

As to Wisconsin Municipals' assertions that prior individual settlement provisions may exceed the

[440] FERC Stats. & Regs. at 31,769–70; *mimeo* at 397–98.

[441] FERC 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.

[444] FERC Stats. & Regs. at 31,665; *mimeo* at 87–88.

[445] *See also* discussion of prior settlements in Section IV.D.1.c.(2) (Energy Imbalance Bandwidth).

minimum provisions of the pro forma tariff, the Commission believes that such arguments should be addressed on a case-by-case basis. [446]

Two additional points are pertinent. First, we note that although we are not generically abrogating existing transmission contracts, utilities retain whatever existing rights they had to propose unilateral changes under section 205 of the FPA if they want to convert a customer to service under the tariff, and customers retain their section 206 right to seek reformation of existing transmission contracts if they are unjust, unreasonable, unduly discriminatory or preferential. Second, where a utility has treated similarly-situated customers differently—serving one under a more favorable bilateral contract and another under a less favorable tariff provision—traditional undue discrimination remedies may be available.

We deny Blue Ridge's rehearing requests because the Commission does not intend to assume the regulatory responsibility of identifying in the first instance all of the regional practices around the country that could (and should) properly be reflected in the compliance tariffs. Transmission customers opposed to deviations related to regional practices not only had the opportunity to protest the compliance filings when they were tendered, [447] but these customers also have the right to file section 206 requests to change these tariffs at any time. In addition, Blue Ridge's request that customers be given 45 days to respond to compliance filings instead of 15 days is moot. In an order issued July 2, 1996,[448] we took three actions to address this concern: (1) we gave entities 30 days, instead of 15 days, to respond to Order No. 888 compliance filings; (2) we agreed to post an electronic version of all Order No. 888 compliance filings on the Commission's Electronic Bulletin Board; and (3) we required all public utilities making a compliance filing to also serve a copy of their filing on electronic diskette to any eligible customer or state regulatory agency requesting a copy. We believe that these actions not only provided all interested parties with access to the compliance filings more quickly, but also provided these parties sufficient time to analyze the information once they received it.[449] Moreover, the time periods provided for making and responding to Order No. 888 compliance filings have expired.

With regard to Blue Ridge's first clarification request, we provide the following guidance. Utilities that had pending open access filings at the time that the Final Rule was implemented had the non-price terms and conditions of those pending tariffs superseded by their Order No. 888 compliance filings. Any customer concerns about the non-rate tariff terms and conditions in the compliance filing should be raised in the compliance docket, and any future customer concerns should be raised in a separate, future section 206 complaint filed by the customer.

Furthermore, we reject Indianapolis P&L's rate issue because, if this utility believes that it operates under special circumstances that require it to use ''non-conforming'' pricing methods, it is free to file such a proposal under section 205. The merits of Indianapolis P&L's arguments are more appropriately addressed in such a section 205 proceeding. The Commission will not alter its generic policy (which is the subject of this rulemaking) merely to address the particular needs of one party.

In addition, with regard to both of Indianapolis P&L's concerns, we note that pursuant to the Commission's July 2 Order, the Commission indicated that it would not address waiver requests in a generic proceeding and that parties would have to file such requests separately for separate docketing. We further note that Indianapolis P&L filed a separate waiver request on July 9, 1996, which was docketed as OA96–81.[450]

We also reject Union Electric's argument that the final rules violate procedural due process. Union Electric has had every opportunity to raise arguments with regard to every step in the Commission's derivation and implementation of the final rules. Moreover, with regard to Union Electric's claim that it was given an inadequate amount of time to comprehend and implement the final rules, we note that virtually every public utility, including Union Electric, complied with the Open Access Rule on a timely basis, and there have been very few complaints that the rules are hard to comprehend.

I. Federal and State Jurisdiction: Transmission/Local Distribution

In the Final Rule, the Commission explained that after reviewing the extensive analysis of the FPA, legislative history, and case law contained in both the initial Stranded Cost NOPR and in the Open Access NOPR, and the comments received on that analysis, it reaffirmed its assertion of jurisdiction over the transmission component of an unbundled interstate retail wheeling transaction.[451] The Commission also reaffirmed and clarified its determinations regarding the tests to be used to determine what constitute Commission-jurisdictional transmission facilities and what constitute state-jurisdictional local distribution facilities in situations involving unbundled wholesale wheeling and unbundled retail wheeling.

The Commission also explained that where states unbundle retail sales, it will give deference to their determinations as to which facilities are transmission and which are local distribution, provided that the states, in making such determinations, apply the seven criteria discussed in the NOPR and reaffirmed by the Commission. In addition, the Commission clarified that there is an element of local distribution service in any unbundled retail transaction, and further clarified other aspects of its jurisdictional ruling to preserve state jurisdiction over matters that are of local concern and will remain subject to state jurisdiction if retail unbundling occurs.

The Commission reaffirmed its legal determination that if unbundled retail transmission in interstate commerce occurs voluntarily by a public utility or as a result of a state retail access program, this Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission. The Commission found compelling the fact that section 201 of the FPA, *on its face*, gives the Commission jurisdiction over transmission in interstate commerce (by public utilities) without qualification.

The Commission further explained that when a retail transaction is broken into two or more products that are sold separately, the jurisdictional lines change. In this situation, the Commission emphasized that the state clearly retains jurisdiction over the sale of the power, but the unbundled

[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).

[448] 76 FERC ¶ 61,009 at 61,026–27 (1996) (July 2 Order).

[449] 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.

transmission service involves *only* the provision of ''transmission in interstate commerce'' which, under the FPA, is exclusively within the jurisdiction of the Commission.

The Commission recognized that in asserting jurisdiction over unbundled retail transmission in interstate commerce by public utilities, it was in no way asserting jurisdiction to order retail transmission directly to an ultimate consumer. It explained that its assertion of jurisdiction is that *if* unbundled retail transmission in interstate commerce by a public utility occurs voluntarily or as a result of a state retail wheeling program, the Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission and public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205.

The Commission further clarified that nothing in its jurisdictional determination changes historical state franchise areas or interferes with state laws governing retail marketing areas of electric utilities. It explained that while its jurisdiction cannot affect whether and to whom a retail electric service territory (marketing area) is to be granted by the state, and whether such grant is exclusive or non-exclusive, neither can state jurisdiction affect this Commission's exclusive jurisdiction over transmission in interstate commerce by public utilities.

The Commission also adopted a new section 35.27(b) as follows:

> Nothing in this part (i) shall be construed as preempting or affecting any jurisdiction a state commission or other state authority may have under applicable state and federal law, or (ii) limits the authority of a state commission in accordance with state and federal law to establish (a) competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or (b) non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with state law.

With respect to the Commission's adoption of the Open Access NOPR's functional/technical tests for determining what facilities are Commission-jurisdictional facilities used for transmission in interstate commerce and what facilities are state-jurisdictional local distribution facilities, the Commission concluded that it could not divine a bright line for unbundled retail transmission by the public utility that previously provided bundled retail service to the end user. The Commission added that the limited case law, including *Connecticut Light & Power Company* v. *FPC (CL&P)* and *Federal Power Commission* v. *Southern California Edison Company* (the *Colton* case),[452] supports a case-by-case determination.[453] Accordingly, the Commission stated that its technical test, with its seven indicators, will permit reasoned factual determinations in individual cases.

The Commission made two clarifications regarding local distribution in the context of retail wheeling. First, it explained that even if its technical test for local distribution facilities were to identify no local distribution facilities for a specific transaction, states have authority over the *service* of delivering electric energy to end users. Second, the Commission explained that through their jurisdiction over retail delivery services, states have authority not only to assess retail stranded costs but also to assess charges for so-called stranded benefits, such as low-income assistance and demand-side management.

Thus, under this interpretation of state/federal jurisdiction, the Commission explained, customers have no incentive to structure a purchase so as to avoid using identifiable local distribution facilities in order to bypass state jurisdiction and thus avoid being assessed charges for stranded costs and benefits.

The Commission further determined that it is appropriate to provide deference to state commission recommendations regarding certain transmission/local distribution matters that arise when retail wheeling occurs.

In instances of unbundled retail wheeling that occurs as a result of a state retail access program, the Commission indicated that it will defer to recommendations by state regulatory authorities concerning where to draw the jurisdictional line under the Commission's technical test for local distribution facilities, and how to allocate costs for such facilities to be included in rates, provided that such recommendations are consistent with the essential elements of the Final Rule.[454] Moreover, the Commission indicated that it will consider jurisdictional recommendations by states that take into account other technical factors that the state believes are appropriate in light of historical uses of particular facilities.

As a means of facilitating jurisdictional line-drawing, the Commission stated that it will entertain proposals by public utilities, filed under section 205 of the FPA, containing classifications and/or cost allocations for transmission and local distribution facilities. However, the Commission explained that, as a prerequisite to filing transmission/local distribution facility classifications and/or cost allocations with the Commission, utilities must consult with their state regulatory authorities. If the utility's classifications and/or cost allocations are supported by the state regulatory authorities and are consistent with the principles established in the Final Rule, the Commission indicated that it will defer to such classifications and/or cost allocations.

Furthermore, the Commission stated that deference to state commissions with regard to rates, terms, and conditions may be appropriate in some circumstances. The Commission explained that when unbundled retail wheeling in interstate commerce occurs, the transaction has two components for jurisdictional purposes—a transmission component and a local distribution component. It again emphasized that the Commission has jurisdiction over facilities used for the transmission component of the transaction, and the state has jurisdiction over facilities used for the local distribution component. Thus, the Commission stated, the rates, terms and conditions of unbundled retail transmission by a public utility must be filed at the Commission. However, the Commission added, if the unbundled retail wheeling occurs as part of a state retail access program, it may be appropriate to have a separate retail transmission tariff[455] to accommodate the design and special needs of such programs. In such situations, the Commission indicated that it will defer to state requests for variations from the FERC wholesale tariff to meet these local concerns, so long as the separate retail tariff is consistent with the Commission's open access policies and comparability principles reflected in the tariff prescribed by the Final Rule. In addition, the Commission indicated that

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

[453] 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.

the rates must be consistent with its Transmission Pricing Policy Statement, and the guidance set forth in Order No. 888 concerning ancillary services.[456]

The Commission also expressed concern, just as it did with buy-sell arrangements in the gas industry, that buy-sell arrangements can be used by parties to obfuscate the true transactions taking place and thereby allow parties to circumvent Commission regulation of transmission in interstate commerce. Thus, the Commission reaffirmed its conclusion that it has jurisdiction over the interstate transmission component of transactions in which an end user arranges for the purchase of generation from a third-party. Moreover, the Commission indicated that it will address these transactions on a case-by-case basis.

Rehearing Requests

Oppose Commission Assertion of Jurisdiction Over Unbundled Retail Transmission

Several state commissions indicate that, recognizing that the case law is not dispositive concerning the question of unbundled retail transmission services (either because the cases do not involve the transmission of power to retail customers or ''fence off'' local distribution from federal regulation), at least one court (*Wisconsin-Michigan Power Company* 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.[457] Thus, they argue, the Commission should apply the wholesale versus retail analysis to the question of unbundled retail transmission.

IL Com asserts that retail transmission by a public utility directly to an end user has always (even before the FPA was enacted) been subject to regulation by the states. It contends that no change in law has occurred which justifies the Commission's claim of expanded jurisdiction. Moreover, it disagrees with the Commission's conclusion that the unbundled delivery by the previous public utility generation supplier directly to an end user is in interstate commerce. It argues that the FPA was never intended to disturb the jurisdiction of state regulators that existed prior to its passage and that retail transmission of electric energy by a public utility to an end user was under state jurisdiction before the *Attleboro* decision and has remained under state jurisdiction in the over sixty years following *Attleboro.* Even after unbundling, according to IL Com, transmission to a retail customer still involves a retail sale of transmission.

NARUC and VA Com assert that the legislative history provides little support for the Commission's conclusion that the act of unbundling generation from delivery serves to shift jurisdiction from a state commission to the Commission. If anything, they contend, the jurisdictional structure of the FPA is predicated on the distinction between retail and wholesale transactions, not bundled and unbundled services. They assert that the Commission should conclude that the rates, terms and conditions of service for delivery of power by a utility to an end-use customer are subject to the jurisdiction of the state commission regulating the utility, regardless of the identity of the party generating or reselling the power or the facilities used to transport the power.

NARUC asserts that the Commission did not address a point raised in NARUC's reply comments as to how the removal of generation serves to unbundle the retail delivery function into separate transmission and distribution services. It maintains that the Commission simply assumes that a resulting transmission transaction is created when power is sold to a retail consumer by someone other than the utility delivering the power.[458]

MI & NH Coms ask the Commission to vacate those portions of the Rule that find that the Commission has jurisdiction over the transmission component of an unbundled retail sale in a local retail wheeling transaction. They assert that the Commission should confine its activity to wholesale transactions or those interstate transactions that do not implicate matters of local concern. They argue that the dual federal/state regulatory scheme establishes that Congress' intent is that state regulation of retail wheeling *is not* preempted by federal law as established in FPA section 201. They oppose unnecessary federal intrusion into local matters under a one-size-fits-all approach and assert that the retail wheeling initiatives in New Hampshire and Michigan are tailored to the unique utility environment in each state.

Central Illinois Light argues that unbundling of retail electric service does not change the states' longstanding jurisdiction over retail electric service and local distribution, even when that service involves the use of transmission in interstate commerce. It asserts that 201(b)(1) (''transmission of electric energy in interstate commerce'') cannot be read in a vacuum.

MN DPS & MN Com and OH Com assert that the Commission should have no role in the regulation of retail services, be they bundled or unbundled. They argue that, in refusing to grant the Commission authority over retail wheeling, Congress left jurisdiction over retail electric service to the states. They conclude that the Final Rule contains insufficient legal and/or policy justification for the Commission's assertion of jurisdiction over unbundled retail transmission services.

MN DPS & MN Com assert: ''FERC bases its usurpation of state authority over retail transmission rates on its claim that balkanization would occur without the assertion of FERC authority. Therefore, the parties are entitled to rehearing so that this essential issue can be further analyzed.'' (MN DPS & MN Com at 1–3).

FL Com argues that the Commission has not justified why the act of unbundling prices expands the Commission's jurisdiction into retail marketing areas. It argues that Section 212(g) of the FPA has the effect of prohibiting the Commission from usurping existing state jurisdiction over retail transmission service, whether bundled or unbundled. According to FL Com, FERC's jurisdiction over transmission terminates at the territorial boundary of each electric utility in Florida. It supports wheeling in jurisdiction for state commissions and wheeling out and wheeling through jurisdiction for the Commission.

IN Com opposes federalization of retail wheeling transactions within a state's boundaries as contrary to the FPA's legislative history and case law.

NJ BPU asserts that by claiming jurisdiction over unbundled retail transmission, the Commission is creating a disincentive for states to implement retail access because, by ordering retail access, the states may be relinquishing their jurisdiction over unbundled retail transmission terms and conditions—jurisdiction that they would maintain under a bundled scenario.[459] PA Com argues that the Commission does not have the authority

[456] 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.

to order retail wheeling and that the jurisdictional formula is challengeable on engineering and legal grounds. It concludes that the Commission does not have jurisdiction over unbundled interstate retail transmission service. PA Com notes that the 1996 House and Senate hearings have raised the question whether the Commission has the statutory authority to restructure the electric industry. PA Com questions the Commission's definition of the ''traditional tasks of state and federal regulators'' on the basis of section 201(b) of the FPA, the Supremacy Clause, and the Tenth Amendment of the U.S. Constitution.

Support Broader Assertion of Jurisdiction by the Commission Over Retail Wheeling

NY Utilities declare that the Commission has jurisdiction over retail wheeling from the source to the load, but does not have jurisdiction over transmission in bundled retail service. They assert that the Commission's reliance on state jurisdictional local distribution as a predicate to abstain from allowing retail wheeling stranded cost recovery is without foundation. They further assert that a unique element that sets local distribution apart from transmission is not the size of the facility or the length of travel, but that transportation is bundled with a retail sale. According to NY Utilities, the plain meaning of the FPA shows that local distribution is bundled retail service. They claim that the legislative history, to the extent necessary, and court cases support FERC jurisdiction over all aspects of retail wheeling, but makes clear that the Commission cannot regulate bundled retail service. They add that the NGA also demonstrates that local distribution means bundled retail service.

Commission Conclusion

In concluding that this Commission has exclusive jurisdiction over the rates, terms and conditions of unbundled retail transmission by public utilities in interstate commerce, the Commission in Order No. 888 thoroughly examined the statutory language of the FPA and its legislative history, and relevant FPA and NGA case law. While the state commissions on rehearing would like us to draw a bright line that gives them, to varying degrees, jurisdiction over retail interstate transmission by public utilities, no party on rehearing has raised any legislative history or case law that was not previously considered and that would support the proposition that states have jurisdiction over any unbundled transmission in interstate commerce. As explained below, we reaffirm our jurisdictional interpretation on rehearing and believe that it is supported by the recent decision in *United Distribution Companies* v. *FERC.*[460]

Many of the rehearing arguments focus on the fact that states historically (even prior to the FPA) regulated retail transmission insofar as it was a component of bundled electric service to an end user, and they argue that by asserting jurisdiction over unbundled retail transmission, the Commission is somehow ''taking away'' jurisdiction the states previously had. The flaw in these arguments is their inherent assumption that jurisdiction over transmission service turns upon the question of whether the transmission service is being provided for ''wholesale'' or ''retail'' power sales. That is not the case. The question of jurisdiction rather turns upon the extent of the Commission's exclusive jurisdiction over transmission in interstate commerce under the FPA. The fact that states historically regulated most retail transmission service as a part of a bundled retail power sale is not the result of a legal requirement; it is the practical result of the way electricity has historically been bought and sold. However, the shape of power sales transactions is rapidly changing. Rather than claiming ''new'' jurisdiction, the Commission is applying the same statutory framework to a business environment in which, as discussed below, retail sales and transmission service are provided in separate transactions.

In the past, retails ales occurred almost exclusively on a bundled basis (*i.e.,* the same entity provided a delivered product called electric energy and transmission was part and parcel of that product). The FPA clearly reserves the right to regulate retail sales of electric energy to the states. As we explained in the Final Rule, however, in today's markets, and increasingly in the future as more states adopt retail wheeling programs, retail transactions are being broken into products that are being sold separately: transmission and generation. Moreover, these products are being sold increasingly by two or more different entities. For example, a transaction may involve transmission service from one or more transmission providers who move power from a distant generation supplier, over the interstate transmission grid, to an end user. Because these types of products and transactions were not prevalent in the past, the jurisdictional issue before us did not arise and, contrary to IL Com's argument, the Commission cannot be viewed as ''disturbing'' the jurisdiction of state regulators prior to and after the *Attleboro* case.[461]

As we also explained in the Final Rule, the legislative history of the FPA and the relevant case law similarly reflect the historical market structure in which electricity and transmission generally were bought on a bundled basis.[462] Today's unbundled world simply was not contemplated and the cases do not resolve dispositively this jurisdictional issue. The case law focuses primarily on the bright line between wholesale sales and retail sales of *energy,* and transmission in interstate as opposed to intrastate commerce. It does not address unbundled retail interstate transmission.[463] We therefore have interpreted the case law in light of changed circumstances and have relied in the first instance on the plain wording of the statute. We find compelling that section 201 of the FPA, on its face, gives the Commission jurisdiction over transmission in interstate commerce without qualification; unlike our jurisdiction over sales of electric energy, which section 201 specifically limits to sales at wholesale, the statute does not limit our transmission jurisdiction over public utilities to wholesale transmission.

Since the time Order No. 888 issued, the D.C. Circuit has addressed a similar issue in interpreting section 1(b) of the NGA, the provision that parallels section 201(b) of the FPA. Under section 1(b), the Commission's jurisdiction does not apply ''to the local distribution of natural gas or to the facilities used for such distribution.'' Similarly, under section 201(b) of the FPA, the Commission shall not have jurisdiction, except as specifically provided, ''over

[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.

[463] 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.

facilities used for the generation of electric energy or over facilities used in local distribution * * *'' In responding to arguments regarding the scope of state authority over ''local distribution'' of natural gas, the court distinguished between bundled and unbundled sales:

> States have been—and are still—permitted to regulate LDCs' bundled sales of natural gas to end-users because those transactions include transportation over local mains and the retail sales of gas. In contrast, states have *never* regulated the terms and conditions of interstate pipeline transportation. When the gas sales element is severed—*i.e.,* unbundled—from the transactions, FERC retains jurisdiction over the *interstate transportation* component.'' [United Distribution Companies, 88 F.3d at 1153 (footnote omitted) (emphasis in original).]

The court's reasoning is also applicable to and supports our jurisdictional determination in Order No. 888.

Several state commissions point to section 212(h) of the FPA and argue that Congress, in refusing to grant the Commission authority to order retail wheeling, left all jurisdiction over retail transmission to the states. We disagree. What Congress did in section 212(h) was to prohibit us from *ordering* transmission directly to an ultimate consumer. We readily recognize and respect this prohibition. However, the ability to order retail wheeling is a separate issue from whether we have jurisdiction over the rates, terms and conditions of retail wheeling in interstate commerce that is ordered by a state or that is provided voluntarily. Congress, in enacting section 212(h), did nothing to modify our jurisdiction under sections 201, 205 and 206 over the rates, terms and conditions of interstate transmission by public utilities.

Similarly, we reject FL Com's arguments that section 212(g) of the FPA prohibits the Commission from asserting any jurisdiction over unbundled retail transmission. Section 212(g) prohibits the Commission from issuing an order that is inconsistent with any state law that governs retail marketing areas of electric utilities. As we stated in the Final Rule, while our jurisdiction cannot affect whether and to whom a retail electric service territory (marketing area) is to be granted by the state, and whether such grant is exclusive or non-exclusive, neither can state jurisdiction affect this Commission's exclusive jurisdiction over the rates, terms and conditions of transmission in interstate commerce by public utilities. We also reject arguments by the FL Com that this Commission's jurisdiction over transmission terminates at the territorial boundary of each electric utility in Florida. This argument is flatly contrary to the longstanding interpretation of the FPA by the United States Supreme Court.[464]

Commission's Seven Factor Test

IL Com argues that the Commission should withdraw its technical test. It contends that retail wheeling jurisdiction should follow function and that the function served by public utility facilities in providing retail service does not change upon the unbundling of service to retail customers. According to IL Com, Commission jurisdiction would extend to the service of delivering electric energy by a public utility to wholesale customers, regardless of the nature and extent of the public utility's facilities used to make that delivery. Similarly, it asserts, state jurisdiction would extend to the service of delivering electric energy by a public utility directly to retail customers, regardless of the nature and extent of the public utility's facilities used to make that delivery.

NARUC argues that the seven-factor test does not result in the bright line discussed in *FPC* v. *Southern California Edison Company,* 376 U.S. 205 (1964). The facility-by-facility categorization of utility systems on a company-specific basis, it asserts, is hardly consistent with the Court's decision to make case-by-case analysis unnecessary.

OH Com asserts that the seven factors provide no useful insight into the nature of local distribution service. It adds that reliance upon technical tests to determine local distribution lacks legal foundation. It further contends that the jurisdictional bright line established by Congress focuses upon the nature of the transaction, not the functional or technical characteristics of a particular wire, in determining whose jurisdictional authority attaches to a particular transaction and facilities. It concludes that the Commission should adopt the Ohio-proposed retail marketing area ''wheeling in'' jurisdictional approach.

PA Com contends that the Commission's seven indicia are not acceptable measures of local distribution and challenges each factor.

NH & MI Coms declare that the criteria for distinguishing transmission facilities from local distribution facilities should not be limited to the seven given in the Rule, but should allow consideration of any other relevant criteria for separating local concerns from matters legitimately federal in nature.

NJ BPU argues that the engineering-driven definition does not resolve many of the hazy areas. To the extent that the seven factors do not reflect or cannot be reconciled with the particular circumstances, it contends that the states may be hamstrung in their ability to make reasoned decisions that comport with Order No. 888.[465]

Similarly, NY Com argues that five of the seven factors (1, 2, 4, 6, and 7) are not accurate when applied to large metropolitan areas and remote rural areas. It asserts that local distribution facilities are not necessarily close to retail customers and the assumption that local distribution facilities are primarily radial in character fails to account for network systems. It adds that reconsignment or transportation of power to different markets can and does occur at the local distribution level. It further adds that the presence of meters is not a discerning characteristic of where interstate transmission ends and local distribution begins; meters are frequently not part of the transmission/local distribution interface. Nor, according to NY Com, are local distribution systems necessarily of reduced voltage. Instead of the 7 criteria, NY Com argues that the Commission should adopt a functional measure of local distribution based on factors 3 and 5 (interstate transmission ends and local distribution begins where electricity flows into a comparatively restricted geographic area and does not flow back out of that area and the power is consumed in that area) and on the traditional classification of the facilities by the state regulatory body (or what the utility has traditionally classified as local distribution).

Commission Conclusion

Several parties on rehearing do not like the seven-factor technical test for local distribution facilities that was set forth in Order No. 888. That test takes into account both technical and functional characteristics of the transaction involved. The parties on rehearing propose instead a variety of bright line tests. For example, IL Com wants state jurisdiction to extend to the ''service'' of delivering electric energy to retail customers, which it would define to give it jurisdiction regardless of the

[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).

nature and extent of the facilities used to make the delivery. OH Com proposes that the Commission adopt a retail marketing area ''wheeling in'' jurisdictional approach which would give it jurisdiction over facilities within territorial boundaries.

In response, we do not interpret the FPA to permit us in effect to rewrite the statute to give states jurisdiction over interstate transmission services. Moreover, we reject arguments of OH Com that our seven-factor test lacks legal foundation, and arguments of NARUC that we are somehow bound to develop a bright line test. While Congress established a jurisdictional bright line between wholesale and retail sales of energy, there is no such bright line that we can divine with regard to transmission and local distribution facilities. The Supreme Court, in both *Colton* and *CL&P*,[466] has instructed us that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. The seven factors will permit us to undertake this fact-specific determination.

We acknowledge the concerns raised by several state commissions that the seven-factor test does not, as NJ BPU puts it, resolve many of the hazy areas, and that there may be other factors that should be taken into account in particular situations. The seven-factor test is intended to provide sufficient flexibility to take into account unique local characteristics and historical usage of facilities used to serve retail customers. We specifically stated in the Final Rule that we will consider jurisdictional recommendations by states that take into account other technical factors that states believe are appropriate in light of historical uses of particular facilities. Moreover, we will defer to facility classifications and/or cost allocations that are supported by state regulatory authorities. For example, in the ongoing California electric utility restructuring proceeding, the Commission deferred to the State PUC's recommendations regarding the split between state jurisdictional local distribution facilities and Commission-jurisdictional transmission facilities.[467]

Oppose Transmission of Public Utility Purchases for Sale at Retail

IL Com objects to the transmission unbundling requirement if it is intended to require public utilities to take transmission services under their own FERC tariffs for purchases of power intended for distribution by the public utility to retail customers. According to IL Com, a distinction must be made between the public utility's use of its transmission system in cases in which the public utility purchases wholesale power for sale for resale, and cases in which the public utility purchases wholesale power to serve native load retail customers. It argues that the Commission cannot legally regulate, or place conditions on, the manner in which a utility uses its transmission system to make sales of electric energy at retail. It contends that the Commission must exempt public utility power purchases for sale at retail from the unbundling requirement. It recommends that the Commission insert the words ''for sale for resale'' after the word ''purchases'' in section 35.28(c)(2) and after the word ''purchase'' in section 35.28(c)(2)(i).

Commission Conclusion

The Commission rejects arguments of IL Com that if unbundled retail wheeling occurs either voluntarily or as a result of a state retail program, we cannot require the utility to take service under its own transmission tariff for sales to retail customers. This requirement is a term and condition of unbundled retail interstate transmission service and, as explained above, therefore is within our exclusive jurisdiction. Additionally, this should not in any way infringe on state retail programs or service to retail customers. Rather, it ensures that non-discriminatory transmission services are provided to all potential retail power competitors.

Further, as stated previously in Section IV.C.1.b (Transmission Providers Taking Service Under Their Tariff), we clarify that a transmission provider does not have to ''take service'' under its own tariff for the transmission of power that is purchased on behalf of bundled retail customers.

Oppose Buy-Sell Transaction Analysis

PA Com asserts that there is a potential for jurisdictional conflict with respect to buy-sell transactions that is a direct consequence of the technical-functional test (which PA Com challenges).

IL Com argues that states have exclusive authority to regulate buy-sell arrangements as bundled retail sales. It further argues that the Commission cannot make a bundled retail sale into an unbundled retail sale simply by characterizing it as the functional equivalent of an unbundled retail sale; by re-characterizing them the Commission is effectively ordering the unbundling of buy-sell arrangements. It asserts that buy-sell arrangements on the electric side are not an end run around clear federal jurisdiction and that the Commission should withdraw its assertion of jurisdiction over the retail transmission component of unbundled retail sales.

VT DPS contends that the Commission's rationale is flawed: ''FERC's analysis rests on the same very shaky ground as its similar claim of jurisdiction over buy-sell arrangements by local gas distribution companies.'' According to VT DPS, all retail transactions are subject to state jurisdiction and asks the Commission to clarify that the Commission defines buy-sell as it did in the NOPR, but also acknowledge that it has no jurisdiction over such arrangements.

IN Com asserts that in the absence of any record of abusive and undermining actions by states under the guise of buy-sell arrangements, there is not even a remedial justification to touch buy-sell transactions. It contends that a difference between the FPA and the NGA warrants different treatment—the FPA exempts from FERC jurisdiction local distribution and transmission of electric energy in intrastate commerce. By redefining interstate transmission, IN Com claims that the Commission proposes to do away with the meaning history has accorded to a variety of transactions previously considered wholly intrastate in nature. According to IN Com, states should be allowed to experiment with and allow different forms of buy-sell transactions as part of the evolving marketplace.

Commission Conclusion

Four parties (PA Com, IL Com, VT DPS and IN Com) have raised concerns regarding the Commission's determination that it has jurisdiction over the interstate transmission component of transactions in which an end user arranges for the purchase of generation from a third party. The Commission reiterates that we will have to address these situations on a case-by-case basis. We disagree with IL Com that States have exclusive authority to regulate the interstate transmission component of buy-sell transactions. Similarly, we deny the VT DPS request that we acknowledge no jurisdiction over such arrangements. The fact remains that these arrangements *could* be used by parties to obfuscate the true transactions taking place and thereby allow parties to circumvent Commission regulation of transmission in interstate commerce. We reserve our authorities to ensure that public utilities and their

[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).

customers are not able to circumvent non-discriminatory transmission in interstate commerce. In response to VT DPS' contention that the Commission's analysis here rests on the same shaky ground as its similar claim of jurisdiction over buy-sell arrangements by local gas distribution companies, we note that the D.C. Circuit recently affirmed the Commission's assertion of jurisdiction over buy/sell arrangements under the Natural Gas Act.[468]

State Jurisdiction Over the Service of Delivering Electric Energy to End Users

Rehearing Requests

IL Com states that it is far from clear what FERC contemplates by the ''service'' of delivery of electric energy by a delivering utility in the retail wheeling transaction. It is equally unclear to IL Com whether the ''service'' to which Order No. 888 refers is a public utility activity over which state regulators would have jurisdiction. IL Com argues that it is the Illinois legislature, not FERC, that determines whether IL Com can regulate something called ''delivery service.''[469]

MO/KS Coms ask the Commission to clarify the meaning of the statement that even when the test for local distribution facilities identifies no local distribution facilities, the Commission believes that states have authority over the service of delivering electric energy to end users. According to MO/KS Coms:

> The authority to shop at retail and to sell at retail do not exist in the FPA. If the Commission's goal is to recognize the States' authority to establish conditions on retail competition, it need only acknowledge the State jurisdiction to establish the opportunity to shop and sell at retail. If this is what the Commission is seeking to accomplish by its discussion of 'delivery service,' then we support the Commission.[470]

Coalition for Economic Competition asserts that the Commission failed to consider that the sale of electric energy may take place outside of the state into which the energy is transmitted, and that the local regulatory commission may have no jurisdiction over either the sale or the transmission of the energy.

Commission Conclusion

Several parties ask us to clarify our conclusion that even when the seven-factor test for local distribution facilities does not identify local distribution facilities, we believe states have authority over the ''service'' of delivering electric energy to end users. We clarify that states have the authority to determine the retail marketing areas of electric utilities within their jurisdictions, and the end user services that those utilities must provide, but we did not in Order No. 888 intend to opine on the extent of authority given by state legislatures to their state commissions. Rather, our statement regarding state authority over the ''service'' of delivering electric energy is intended to recognize the historical and local nature of delivering power to end users and the states' legitimate concerns and responsibilities in regulating local matters.

Deference to States

Rehearing Requests

Support Broader Deference

NARUC and IL Com argue that the Commission should not simply defer to state recommendations concerning the application of the seven-factor test or the recovery of stranded costs, but should conclusively rely on the findings by state commissions.

NY Com argues that the Commission should not limit deference to instances in which states order retail wheeling, but should defer to all state commission recommendations regarding the definition of local distribution facilities.

FL Com asserts that the Rule fails to say where deference will be given. It argues that the Rule should state that when a state commission has held a proceeding on matters related to the requirements of the Rule, the Commission shall give deference to the state commission decisions. Moreover, it asserts that the Commission should codify the deference standard: ''When a state commission has held a proceeding on matters related to the requirements of this rule, the Commission shall give deference to the state commission decisions.'' (FL Com at 7–9).

The commitment to defer to a state regulatory commission or agency, argues NE Public Power District, should be clarified with respect to utilities located in Nebraska, which has no such commission or agency. NE Public Power District assumes that deference will be accorded to decisions of NE Public Power District's Board of Directors; if not, it asks the Commission to clarify.

PA Com asks the Commission to clarify what a state regulatory agency must demonstrate to secure deference and to define the term ''consult.'' PA Com states that, in discussing the seven indicia, the Commission states that it will ''consider'' jurisdictional recommendations by states, which PA Com asserts is much different from deference. It also asserts that the Commission must clarify what it will do if a utility's classifications and/or cost allocations are not supported by state regulatory authorities.

Oppose Deference to State Authorities

TANC argues that the Commission erred in deferring to state regulatory authorities in drawing jurisdictional lines for local distribution facility classifications and/or cost allocations. According to TANC, the Commission unlawfully and unnecessarily abdicated its jurisdiction under the FPA (citing *New England Power Co.* v. *New Hampshire*, 455 U.S. 331, and *Nantahala Power and Light Co.* v. *Thornburg*, 476 U.S. 953). With respect to ISOs, it asserts that the Commission should not defer to state authority in making determinations with respect to classifications of facilities.

Commission Conclusion

In response to NARUC and IL Com's arguments that this Commission should not simply defer to state commissions regarding application of the seven-factor test but instead should conclusively rely on the findings of state commissions, we believe this is inconsistent with the case law which states that local distribution it is a matter of fact for the Commission to determine as an original matter.[471] Additionally, we have an independent obligation to ensure that we are fulfilling our responsibilities under the FPA to regulate facilities that are used in interstate commerce. We cannot delegate our jurisdiction. However, we intend to provide broad deference to states in determining what facilities are Commission-jurisdictional transmission facilities and what facilities are state-jurisdictional local distribution facilities, so long as our comparability principles are not compromised and we are able to fulfill our responsibilities under the statute.

We reject FL Com's suggestion that we codify the deference standard. This is neither necessary nor appropriate. In response to NE Public Power District's request that we clarify to whom we would give deference in Nebraska, we clarify that because Nebraska does not have an electric regulatory commission or agency, there is no appropriate regulatory entity to whom our deference standard would apply; accordingly, we will address the transmission/local

[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.*

distribution issue for Nebraska without giving deference to any particular entity. In response to PA Com's request that we clarify what we will do if a utility's classifications and/or cost allocation proposals are not supported by state regulatory authorities, we will make a determination based on the factual record before us in a particular case, taking into account the views of the state regulatory authority.

TANC has argued that we have unlawfully abdicated our jurisdiction by deferring to state recommendations. TANC confuses delegation of jurisdiction, which we cannot do, with willingness to defer to states based on their application of criteria that we have provided. Even in the cases in which the Commission defers to states' views, we will still independently evaluate all material issues and proceed only where substantial evidence supports the states' views. The Commission clearly can entertain requests for deference in these circumstances.

J. Stranded Costs

As indicated in our prior discussion in Section IV.A.5, there are two major overlapping transition issues that arise as a result of this rulemaking: stranded cost recovery and how to deal with contracts entered into under the prior regulatory regime. We here address stranded cost recovery and, as in the prior discussion, we believe it is important to explain the general context in which our stranded cost determinations have been made before addressing the various rehearing requests on this issue.

In Order No. 888, the Commission removed the single largest barrier to the development of competitive wholesale power markets by requiring non-discriminatory open access transmission as a remedy for undue discrimination. This action carries with it the regulatory public interest responsibility to address the difficult transition issues that arise in moving from a monopoly, cost-based electric utility industry to an industry that is driven by competition among wholesale power suppliers and increasing reliance on market-based generation rates. The most critical transition issue that arises as a result of the Commission's actions in this rulemaking is how to deal with the uneconomic sunk costs that utilities prudently incurred under an industry regime that rested on a regulatory framework and a set of expectations that are being fundamentally altered.

The Commission determined in Order No. 888 that it must address stranded costs, and that it must do so at an early stage—particularly in light of the lessons learned from our experience with similar issues in the natural gas area. We noted that when we did a similar restructuring in the gas industry, the D.C. Circuit invalidated the Commission's efforts precisely because the Commission had failed to deal with the stranded cost problem in a satisfactory manner.[472] We explained that, based on the lesson of *AGD*, the Commission cannot change the rules of the game without providing a mechanism for recovery of the costs caused by such regulatory-mandated change.

Since the time Order No. 888 issued, we have been provided with additional guidance from the court in the natural gas area, which has further helped to inform our decisions here. In its decision on review of Order No. 636,[473] the D.C. Circuit upheld the Commission's decision to allow the recovery of gas supply realignment costs. In so doing, the court, while questioning a specific feature of the stranded cost recovery mechanism employed in Order No. 636, has nevertheless again reaffirmed the basic principle that stranded cost recovery is an appropriate component of a regulatory policy aimed at accomplishing a fair and reasonable transition to competitive markets. The question as to the Commission's ability to allow the recovery of stranded costs has been laid to rest.

The task before the Commission in this rulemaking is thus to determine how best to meet its responsibility to address the costs of the transition to a competitive industry, particularly insofar as those costs are stranded, or in effect rendered unrecoverable, as a result of the transmission access required by us under the FPA.[474] As the rehearing arguments demonstrate, there is no consensus on how the Commission should address the stranded cost issue. In fact, petitioners are at polar extremes as to what the Commission should do regarding stranded costs. Some argue that the Commission has gone too far in permitting utilities to seek recovery of stranded costs, whether such costs are associated with wholesale requirements contracts, with retail-turned-wholesale customers, or with retail customers that obtain retail wheeling.[475] Others argue that the Commission has not gone far enough and that it must broaden the scope of stranded cost recovery permitted under the Rule. Indeed, some would have us be the guarantor for recovery of all uneconomic costs that might be stranded in the move to more competitive markets, no matter how tenuous the nexus to this Rule, and irrespective of state-Federal jurisdictional complexities. Some support the Commission's decision to recover stranded costs directly from the departing customers. Others would prefer that the Commission require utilities to absorb a portion of their stranded costs or that the Commission spread the burden of stranded costs among all of the utility's customers. Some object that the Commission's approach to stranded costs in the electric industry is different from that adopted in the gas industry. Some entities support the Commission's revenues lost approach for measuring a departing customer's stranded cost obligation. Others propose different methods for computing stranded costs.

Given the plethora of positions that entities have raised both initially and on rehearing concerning stranded costs, the Commission has taken a careful, measured approach with regard to stranded cost recovery. The Commission has balanced a number of important interests in order to achieve what it believes will be a fair and orderly transition to competitive markets. These interests include the financial stability of the electric utility industry, upholding the regulatory bargain under which utilities made major capital investments, and not shifting costs to customers that had no responsibility for causing those costs to be incurred. The Commission also has adopted an approach that, for purposes of stranded cost recovery from wholesale transmission customers, relies on the nexus between stranded costs and the use of transmission tariffs required by this Commission and, for purposes of stranded cost recovery from retail customers, recognizes state commission

[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.

[475] 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.

jurisdiction but fills potential regulatory gaps that could arise in the transition to new market structures.

The balancing of interests and considerations described above is reflected in the following central components of the Rule's stranded cost provisions, which are reaffirmed herein.[476] First, the Commission has determined that the most reasonable, legally supportable approach is one that permits utilities to seek recovery of wholesale stranded costs under this Rule (whether the stranded costs are associated with a departing wholesale requirements customer or with a retail-turned-wholesale customer) only in those cases in which there is a *direct nexus* between the availability and use of Commission-required transmission access [477] and the stranding of costs. In order for the utility to be eligible to seek recovery of stranded costs from a departing customer, the customer must have obtained access to a new generation supplier through the use of the former supplying utility's Commission-required transmission tariff (*i.e.*, its open access tariff or a tariff ordered pursuant to FPA section 211), not through the use of another utility's transmission system.

Other cost recovery issues are more appropriately addressed outside the context of this Rule. For example, the Rule is *not* intended to apply to costs associated with the normal risks of competition, such as self-generation, cogeneration, or loss of load, that do not arise from the new, accelerated availability of Commission-required transmission access. If a customer leaves its utility supplier by exercising options that could have been undertaken prior to mandatory transmission under Order No. 888 or the Energy Policy Act, or that do not rely on access to the former seller's transmission, there is no direct nexus to Commission-required transmission access and thus no opportunity for stranded cost recovery under the Rule.

Second, the Commission has limited the opportunity to seek stranded cost recovery under the Rule primarily to two discrete situations: (1) Costs associated with customers under wholesale requirements contracts executed on or before July 11, 1994 (referred to in the Rule as ''existing wholesale requirements contracts'') that do not contain an exit fee or other explicit stranded cost provision; and (2) costs associated with retail-turned-wholesale customers. With regard to the existing wholesale requirements contracts, the Commission also has made a finding that it is in the public interest to permit amendments to add stranded cost provisions to these contracts, even if they contain *Mobile-Sierra* clauses, if case-by-case evidentiary burdens are met. We do not interpret the *Mobile-Sierra* public interest standard as practically insurmountable in extraordinary situations such as this one where historic statutory and regulatory changes have converged to fundamentally change the obligations of utilities and the markets in which they and their customers will operate.

Third, Order No. 888 *does not guarantee* that a utility will be allowed to recover stranded costs. Rather, it provides an *opportunity* for such recovery. To be eligible to recover stranded costs from a departing customer in a particular case, the utility must demonstrate that it incurred costs to provide service to the customer based on a reasonable expectation of continuing service to that customer beyond the contract term.[478] In the case of stranded costs associated with wholesale requirements contracts customers, if the contract contains a notice of termination provision, that provision is strong evidence that the parties were aware that at some point in the future the customer might seek to find another supplier. Therefore, there is a rebuttable presumption of no reasonable expectation, and therefore no opportunity for stranded cost recovery unless the utility can overcome the presumption.

The Commission has concluded that direct assignment of stranded costs to the departing customer (through either an exit fee or a surcharge on transmission) is the appropriate method for recovery of stranded costs under the Rule. In reaching this conclusion, the Commission carefully weighed the arguments supporting direct assignment of stranded costs against those supporting a more broad-based approach, such as spreading stranded costs to all transmission users of a utility's system, and also took into account the fact that we applied a different approach in the natural gas area. The central considerations that support a direct assignment approach in the electric industry are that the approach follows the traditional regulatory concept of cost causation, it avoids shifting costs to customers that had no responsibility for causing them to be incurred or for causing them to be stranded, and it is still possible to apply such an approach at this stage of the industry's evolution.

There is no question that, without the stranded cost recovery mechanism, some customers would be far more likely to switch to lower-cost suppliers and enjoy sooner the benefits of a competitive power market. But, as detailed in Order No. 888, such an approach may result in higher costs for other customers. We thus have had to balance the potential for earlier benefits for some customers against other public interest considerations, most particularly the need to provide a fair mechanism by which utilities can recover the costs of past investments under traditional regulatory concepts of prudently incurred costs and cost causation. The result is not to deny competitive advantages, but only to delay their full realization for some customers so that all customers ultimately will benefit.

While Order No. 888's cost causation approach is different from the Order No. 636 cost spreading approach that was affirmed in the *United Distribution Companies* case, we believe it is the preferable approach given the early stage of the electric utility's competitive transition. We do not read the court's opinion as precluding the Commission from adopting a direct assignment approach in Order No. 888, particularly where, as here, the Commission has fully explained and justified the reasons for following traditional cost causation principles. In addition, although the *United Distribution Companies* court remanded for further consideration (in light of Order No. 636's cost spreading approach) the decision not to require any pipeline absorption of gas supply realignment costs, the Commission has fully explained how its decision in Order No. 888 not to require any utility absorption of stranded costs is consistent with its decision to follow traditional cost causation principles. With respect to the fundamental conclusion that utilities should be permitted an opportunity to recover their prudently incurred costs, Order No. 888 is fully consistent with Order No. 636. Although the Commission in Order No. 888 chose a direct assignment method (rather than the cost-spreading

[476] We reaffirm below our basic determinations, but make certain clarifications on limited issues and grant rehearing on the municipal annexation issue.

[477] 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).

approach in Order No. 636) for purposes of allocating stranded cost responsibility among customers, the approach used by the Commission in Order No. 888 is not governed by decisions in Order No. 636, but in either event the Commission must demonstrate that its choice of methods is based on reasoned decision-making.

In considering the stranded cost issues that may arise in the transition to competitive markets, the Commission also has taken cognizance of significant changes involving retail customers and the stranded cost issues that arise as retail customers convert to wholesale customer status (*e.g.,* through municipalizations) in order to obtain the open access afforded by Order No. 888, or as they obtain retail wheeling required by state commissions. These situations involve new and complex jurisdictional issues and represent the bulk of potential stranded costs facing the industry. We believe it is important to clarify the Commission's decisions as to when it will entertain requests for stranded cost recovery in these situations, and our reasons for doing so.

The Commission's determination that it, rather than the states, should be the primary forum for addressing stranded costs associated with a retail-turned-wholesale customer [479] is limited to those cases in which there is a *direct nexus* between the availability and use of Commission-required transmission access and the stranding of costs. We believe we have both the authority and the obligation to provide an opportunity for stranded cost recovery in these situations because the bundled retail customer would not be able to obtain access to the new supplier *but for* the Commission's order requiring transmission. The creation of a new wholesale entity to purchase power on behalf of retail customers would not, by itself, trigger stranded costs. In the absence of transmission access from the historical supplier of the retail customers, the new entity would have to remain on the historical supplier's generation system because it would have no way to reach other power suppliers, and stranded costs would not occur.[480] Therefore, there is a causal nexus between the stranded costs and the availability and use of the tariff services *required by the Commission.*[481] Moreover, because of this causal nexus between the use of a jurisdictional utility's Commission-required transmission tariff and the potential for foregone revenues by that jurisdictional utility as a result of the Commission-required access, the stranded costs associated with a retail-turned-wholesale customer are properly viewed as economic costs that are jurisdictional to this Commission.

In contrast, in the situation in which a bundled retail customer obtains retail wheeling, stranded costs are directly caused by the availability and use of unbundled retail services *required by the state commission,* not this Commission. [482] Thus, the Commission believes that states, not the Commission, should be the primary forum for costs associated with a bundled retail customer that obtains retail wheeling. The Commission's decision to entertain requests to recover stranded costs caused by retail wheeling in *only* a limited circumstance (where the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required) is based on a policy decision by this Commission that it will step in to fill a regulatory ''gap'' that could result in no effective forum in which utilities would have an opportunity to seek recovery of prudently incurred costs.

Finally, after considering various proposals regarding how stranded costs should be calculated, and reviewing the arguments of petitioners on rehearing, the Commission continues to believe that the revenues lost approach is the fairest and most efficient way to determine the amount of stranded cost assigned to a departing customer during the transition to a competitive wholesale bulk power market. The Commission has rejected an asset-by-asset approach as overly complicated and costly.

We respond below to the specific arguments raised on rehearing and elaborate on the above determinations.

1. Justification for Allowing Recovery of Stranded Costs

In Order No. 888, the Commission concluded that utilities should be given the opportunity to seek recovery of legitimate, prudent and verifiable stranded costs associated with a limited set of wholesale requirements contracts executed on or before July 11, 1994. [483] We stated that utilities that entered into contracts to make wholesale requirements sales under an entirely different regulatory regime should have an opportunity to recover stranded costs that occur as a result of customers leaving the utilities' generation systems through Commission-jurisdictional open access tariffs or FPA section 211 orders to reach other power suppliers. We explained that utilities that made large capital expenditures or long-term contractual commitments to buy power years ago to supply their customers should not now be held responsible for failing to foresee the actions this Commission would take to alter the use of their transmission systems in response to the fundamental changes that are taking place in the industry. We found that recent significant statutory and regulatory changes are central to the circumstances that now place at risk the recovery of past investment decisions of utilities. We indicated that we will not ignore the effects of these changes as we fashion policies that will govern possible recovery of these costs in the transition to an open access regulatory regime.

We stated that while there has always been some risk that a utility would lose a particular customer, in the past that risk was smaller. It was not

[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.

[480] 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.

[481] 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.

unreasonable for the utility to plan to continue serving the needs of its wholesale requirements customers and retail customers, and for those customers to expect the utility to plan to meet their future needs. We concluded that with the new open access transmission, [484] the risk of losing a customer is radically increased. If a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, the utility is entitled to seek recovery of legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer. The utility, however, would have the burden of demonstrating that it had a reasonable expectation of continuing to serve the departing customer.

Rehearing Requests Opposing, or Seeking Limitations on, Stranded Cost Recovery

Several entities challenge the Commission's decision to give utilities an opportunity to recover legitimate, prudent and verifiable stranded costs. NASUCA argues that the transition to wholesale competition was underway before and apart from the NOPR. It asserts that the drivers of the developing competition include voluntary open access filings by utilities seeking mergers or market-based rate authority and section 211 of the FPA, as amended by the Energy Policy Act of 1992 (Energy Policy Act). According to NASUCA, stranded investment results from legislative, not regulatory action, and the stranded cost issue does, and would, exist without the Open Access Rule. It contends that an acceleration of the competitive wholesale transformation does not change its nature or origins. NASUCA also contends that the issuance of the Open Access Rule does not justify stranded cost recovery on ''regulatory compact'' grounds because it is not a fundamental change.

Other entities object that there is no basis for the Commission to impute an extra-contractual obligation to serve wholesale requirements customers.[485] These entities argue, for example, that utilities could and should have protected themselves from any potential stranded costs through individual customer contracts.

IN Consumer Counselor and IN Consumers object that Order No. 888 attempts to transform the obligation to provide a utility with an ''opportunity'' for a fair return when prices are regulated into an ''entitlement'' to ''recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime.'' [486]

Several entities submit that the Commission has not adequately addressed the potential anticompetitive impact of stranded cost recovery.[487] Some argue that giving utilities the opportunity to recover wholesale stranded costs will delay the opportunity for historically captive customers to benefit from competitive alternatives.[488] Central Illinois Light contends that the Rule is arbitrary and capricious because it will have different impacts on different customers, which Central Illinois Light asserts will be due to accidents of circumstance rather than the conscious application of rational policy choices. IN Consumers objects that two similarly-situated customers of the utility for identical transmission services will be required to pay substantially different rates for the same service (where one previously purchased its power requirements from the utility, while the other used an alternate source of supply).

Central Illinois Light also objects that even a partial allowance of stranded costs will likely encourage predatory pricing. It says that the Commission has failed to adequately address the harm that stranded cost ''subsidies'' pose to low-cost utilities with little or no stranded costs. Others contend that the Rule would subvert economic efficiency by unjustly enriching utilities that have not attempted to meet the new market demands, to the detriment of those utilities that have.[489] According to Occidental Chemical, the Commission has made no finding that the pro-competitive goals of Order No. 888 can be accomplished in light of the costs and uncertainties presented by stranded cost recovery.

Several entities also challenge the adequacy of the factual record for allowing wholesale stranded cost recovery and argue that utilities have not provided the hard data on wholesale stranded costs that the Commission needs to justify Order No. 888.[490] Central Illinois Light objects that the Commission failed to note or to discuss data presented by commenters showing that only a small group of high-cost utilities need some stranded cost protection. American Forest & Paper argues that the Commission has failed to demonstrate on the record the existence of any stranded wholesale investment that was or could be caused by the transition to open access transmission.

SC Public Service Authority repeats its earlier request that the Commission deny market-based rate authority to any utility that elects to recover stranded costs from departing customers.[491] It objects that the Commission failed to specifically respond to its previous comments on this issue.

American Forest & Paper objects that utilities that voluntarily filed open access tariffs cannot use the stranded cost rule because their loss of customers cannot be said to have occurred only because of the Rule. It submits that only those utilities who had to be forced to offer open access transmission are being rewarded.

San Francisco asks that the Commission include ''exercise of pre-existing contract rights for transmission and designation of wholesale loads'' or similar language as one of the examples (listed in footnote 718) of situations for which stranded costs may not be sought. San Francisco explains that it wants to ensure that PG&E would not have any basis to argue that any load loss PG&E suffers as a result of San Francisco's designation of municipal loads would be eligible for stranded cost recovery.

Commission Conclusion

We will deny the requests for rehearing of our decision to allow

[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.

[488] *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).

utilities an *opportunity* to seek recovery of legitimate, prudent, and verifiable stranded costs. As we indicated in Order No. 888, we learned from our experience with natural gas that, as both a legal and a policy matter, we cannot ignore these costs. The U.S. Court of Appeals for the District of Columbia Circuit invalidated the Commission's first open access rule for gas pipelines because the Commission failed to deal with the uneconomic take-or-pay situation that many pipelines faced as a result of regulatory changes beyond their control.[492] That same court has subsequently affirmed the Commission's decision to allow the recovery of costs that are stranded in the transition to a competitive natural gas industry, most recently by upholding the Commission's decision in Order No. 636 to allow the recovery of gas supply realignment costs.[493]

Here we are faced, once again, with an industry transition in which there is the possibility that, as a result of statutory and regulatory changes beyond their control, certain utilities may be left with large unrecoverable, legitimate and prudent costs or that those costs will be unfairly shifted to other (remaining) customers. Thus, in order to satisfy our regulatory responsibilities, we must directly and timely address the costs of the transition by allowing utilities to seek recovery of legitimate, prudent and verifiable stranded costs.[494] While the transition to wholesale competition may have begun before the NOPR, we strongly disagree with NASUCA's claim that the Open Access Rule does not justify stranded cost recovery because an acceleration of the transition does not change its nature or origins. The driving force behind the development of wholesale competitive markets is the widespread transmission access made available through Commission-mandated transmission tariffs,[495] including transmission tariffs ordered pursuant to FPA section 211 and the transmission tariffs required by the Commission's Open Access Rule.[496] Furthermore, as explained in the Rule and as further discussed below, it is the ability of customers to obtain readily available Commission-mandated transmission access that significantly increases the potential for wholesale stranded costs.

Order No. 888 requires the functional unbundling of a public utility's wholesale services. Under the Rule, all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce were required by July 9, 1996 to file open access transmission tariffs that contain minimum terms and conditions of non-discriminatory service (or to seek waiver), and to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs. As a result of Order No. 888, wholesale requirements customers that previously were captive customers of their public utility suppliers (*i.e.*, they had no choice but to take bundled sales and transmission services from their suppliers) will be able at the expiration of their contracts to take unbundled transmission service (*i.e.*, transmission-only service) from their former suppliers in order to reach new suppliers. While in the past there has been some risk of stranded costs due to customers ''leaving'' a supplier's system through self-generation or perhaps municipalization, there was little or no ability to shop for alternative power such as that which will occur as a result of readily available Commission-mandated transmission access. Contrary to NASUCA's claims, Order No. 888, coupled with section 211 of the FPA, creates the opportunity, as a matter of law, for an existing wholesale requirements customer to use the transmission owner's facilities to reach a new supplier.[497] This leaves the former supplying utility with significant risk that it will be unable to recover costs that the utility incurred based on a reasonable expectation that it would continue to serve the departing customer.

Thus, the regulatory and statutory changes contained in Order No. 888 and in amended section 211, which will act in tandem to provide the transmission access necessary to develop the competitive wholesale markets envisioned by Congress in the Energy Policy Act, have a direct nexus to the potential for wholesale stranded costs. This nexus makes it critical that the Commission address this transition issue responsibly and equitably. Having balanced the goals of competition, the nexus between potential stranded costs and transmission access, and the regulatory bargain under which utilities invested billions of dollars in reliance on the prior regulatory regime, we believe that utilities are entitled to an opportunity to seek recovery of stranded costs and that our actions in Order No. 888 are not only legally supportable, but also represent sound public policy.

In response to those entities who argue that there is no basis for imputing an extra-contractual obligation to serve wholesale requirements customers, as we explained in Order No. 888, we believe there previously has been an implicit obligation to serve at wholesale in many cases. Such obligation is based, in large part, on the recognition that historically most wholesale requirements customers were captive and had no means of reaching alternative suppliers. The local utility supplied bundled generation and transmission services to these customers on the assumption that they would remain as customers. Accordingly, the utility had a concomitant obligation to plan to supply these customers'

[492] *AGD*, 824 F.2d at 1021.

[493] *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.

[495] 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.

[496] 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.

continuing needs, and planned its system taking account of the wholesale load. In many cases the wholesale customers participated by supplying load forecasts. Consistent with this practical obligation to serve, the Commission viewed the supplying utility as the supplier of first resort, and did not allow a utility to terminate service without prior Commission approval. Before Order No. 888, the Commission's regulations required prior notification and approval of the proposed cancellation or termination of a wholesale requirements contract. We note that although Order No. 888 eliminates the prior notice of cancellation or termination requirement for power sales contracts executed on or after July 9, 1996 (the effective date of the Open Access Rule) that are to terminate by their own terms,[498] it expressly retains the prior notice of cancellation or termination requirement for any power sales contract executed before that date.

It is important to note, however, that while the stranded cost recovery provisions of the Rule are based on the implicit obligation to serve, the Rule does not *guarantee* any extra-contractual wholesale stranded cost recovery, much less across-the-board recovery of such costs by all public utilities. To the contrary, it provides an *opportunity* for such recovery only for a discrete set of requirements contracts (those executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision), and the Rule requires that a utility must meet a heavy burden of proving eligibility to recover costs in a particular case: before a departing customer is required to pay a stranded cost exit fee or transmission surcharge, the utility must demonstrate that it incurred costs to provide service to a customer based on a reasonable expectation of continuing service to that customer beyond the end of the contract.[499]

We believe that we adequately address in both Order No. 888 and in Section IV.J.2 below the concerns various entities have expressed as to the potential anticompetitive impact of stranded cost recovery. Although we recognize that stranded cost recovery may delay some of the benefits of competitive bulk power markets for some customers, we believe that customers as a whole will benefit from a fair and orderly transition. Indeed, we are particularly concerned that the failure to assign stranded cost responsibilities to customers that have access to alternative suppliers will leave captive customers exposed to the risk of greater cost burdens, thereby shifting to captive customers the costs that were originally incurred for the benefit of the (typically larger) customers who have the flexibility to take early advantage of competing power suppliers. Avoiding this potential cost shifting problem is an important goal of our decision to address the stranded cost problem as part and parcel of the decision to mandate open access. As we said in Order No. 888:

> such transition costs must nevertheless be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets. The stranded cost recovery mechanism that we direct here is a necessary step to achieve pro-competitive results. In the long term, the Commission's Rule will result in more competitive prices and lower rates for consumers.[500]

We do not believe that allowing utilities an opportunity to seek stranded cost recovery will prevent us from achieving the pro-competitive goals of Order No. 888. To the contrary, as discussed below in Section IV.J.3, we think that it is necessary to provide utilities the opportunity to seek to recover stranded costs if we are to have a fair and orderly transition to more competitive bulk power markets. The opponents of Order No. 888's stranded cost approach argue that the transition to fully competitive bulk power markets will be slower if we allow utilities an opportunity to seek to recover stranded costs from departing customers, and with respect to some customers that may well be true. As noted earlier, some customers because of their size and limited contractual obligations with their current utility suppliers have the ability immediately to leave the system. If they are allowed to do so without paying the costs incurred to provide them expected future service, the economic attractiveness of departing the system is obviously enhanced and the benefits of competition, for these customers, obviously come sooner rather than later. However, the pace at which fully competitive markets are achieved, while important, is not the only consideration. It is the Commission's responsibility to ensure that the costs of open access are fairly assigned and that the benefits of Order No. 888's open access requirements will be fairly available to all customers. These dual goals compel us toward a balanced approach that, although perhaps delaying somewhat the benefits of competition, nevertheless ensures that all customers will share in those benefits without undermining historic principles of cost recovery upon which utilities were entitled to rely in planning their systems.

Moreover, as we explain in Section IV.J.3 below, we have carefully examined different methods of allocating stranded costs that are found to be properly recoverable, including assigning the costs directly to the departing customer or spreading the costs to all transmission users of a utility's system. We recognize that the direct assignment approach to stranded cost recovery delays competition for some customers because it attaches a price tag for customers who have the immediate ability to leave the system. However, we have identified the advantages and disadvantages of each approach and have concluded, on balance, that direct assignment is the preferable approach for both legal and policy reasons.

In response to the concerns of some entities that stranded cost ''subsidies'' may harm low-cost utilities with little or no stranded costs, or otherwise may unjustly enrich utilities that have not attempted to meet the new market demands to the detriment of those that have, we again emphasize the limited and transitional nature of the stranded cost recovery opportunity allowed under Order No. 888.[501] It is clearly not the Commission's intent that utilities with little or no stranded cost exposure be competitively disadvantaged by the Open Access Rule. Those utilities with little or no stranded costs will be similarly situated with other new suppliers in the sense that they will all

[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.

face the potential of not being able to compete immediately for certain wholesale customers who are determined to have an obligation to pay stranded costs. These customers may find it to be uneconomic to shop from new power suppliers because they may have to pay costs they caused to be incurred under the prior industry regime before they are able to switch suppliers. However, this will be during a transition period only, and only with respect to a discrete set of contracts and only where the utility meets its burden of proof with respect to a particular departing customer.

We reject as misplaced IN Consumers' argument that the Open Access Rule is discriminatory because two ''similarly-situated'' customers for ''identical'' transmission services (one who previously purchased transmission bundled with its power requirements from the utility and now seeks to purchase only unbundled transmission, and the other who previously used an alternative source of supply and seeks to purchase unbundled transmission from the utility) will pay substantially different rates for the same service. The error in this argument is that the two customers in the example are *not* ''similarly-situated'' precisely because one of them was a former bundled wholesale requirements customer of the utility for whom the utility may have incurred costs to meet reasonably expected customer demand, whereas the other was never a generation customer of the utility and thus appropriately bears no cost responsibility for stranded generation costs incurred by that utility. Indeed, this example illustrates precisely the reason underlying the Commission's stranded cost mechanism. If a utility had previously served a customer as a seller of generation as well as a transmitter, it is allowed an opportunity to show that it incurred costs based on a reasonable expectation of continuing to serve the power needs of that customer beyond the contract term. Similarly, contrary to Central Illinois Light's claim, if different treatment of different customers were to occur, it would not be due to ''accidents of circumstance''—it would be the result of the conscious application by the Commission of its decision to give a utility the opportunity to recover stranded costs from a wholesale requirements customer if the utility can demonstrate that it incurred costs to provide service to the customer based on a reasonable expectation that it would continue to serve the customer after the contract term.

In response to the claims of those entities that challenge the factual record for allowing wholesale stranded cost recovery, we believe that the record in this proceeding clearly demonstrates the need to give utilities the opportunity to recover wholesale stranded costs. We have shown that the Rule's open access requirement will significantly alter historical relationships among traditional utilities and their customers. Indeed, that is one of its objectives. In the longer term, we seek to have all power supply arrangements priced by the competitive marketplace. However, utilities prudently incurred costs under a prior regulatory regime that created an expectation of an opportunity for recovery of those costs. Common sense indicates that a utility that historically supplied bundled generation and transmission services to a wholesale requirements customer and that reasonably expected to continue to serve the customer may have incurred costs to provide service to that customer that could be stranded if the customer uses open access transmission to reach a new generation supplier.[502] As we learned from our experience in restructuring of the natural gas industry, open access and unbundling did in fact exacerbate the take-or-pay problems in the gas industry because it gave customers more options. That is what we are doing in the electric industry as well. As a result, we have concluded that utilities should be permitted to seek recovery of stranded costs in certain limited and defined circumstances.

We disagree with those entities that argue that utilities have not provided sufficient data on the existence of wholesale stranded costs to justify the approach adopted by the Commission in Order No. 888. Presumably these entities would require us to calculate specific stranded cost estimates for every public utility before we could act to address this critical issue. However, where the Commission decides to act by means of a generic rule,[503] the Commission is not required to make individual findings on a utility-by-utility basis.[504] Moreover, the Rule does not say that all utilities with wholesale contract customers will be allowed to recover stranded costs, only that those utilities that have requirements contracts that were executed on or before July 11, 1994 that do not contain an exit fee or explicit stranded cost provision and that can meet the required evidentiary showing would be allowed such recovery. On this basis, our decision to give utilities the opportunity to seek stranded cost recovery for certain wholesale requirements contracts is not dependent on a showing that any particular utility will actually be eligible to recover stranded costs as a result of the open access requirement.[505]

We also will reject SC Public Service Authority's request that the Commission deny market-based rate authority for all utilities seeking stranded cost recovery. SC Public Service Authority has failed to demonstrate that the ability to seek stranded cost recovery would, by definition, eliminate the potential for mitigation of any generation or transmission market power. If an entity believes that a utility seeking market-based rate authority does not satisfy the Commission's criteria for the grant of market-rate authority (*e.g.*, because the utility has, or has failed to mitigate, market power in generation or transmission), that entity will have ample opportunity to present its case in the market-based rate proceeding.

American Forest & Paper's objection that utilities that voluntarily filed open access tariffs cannot utilize the stranded cost provisions and therefore that only utilities who were forced to offer open access transmission are being rewarded is misplaced. First, there is nothing in Order No. 888 that prohibits a utility that voluntarily filed an open access transmission tariff from seeking recovery of stranded costs if it can demonstrate a reasonable expectation of continuing to serve a particular wholesale customer beyond the term of its existing contract. Second, many of the ''open access'' tariffs accepted prior to Order No. 888, while an improvement upon the status quo of no access, did not contain the minimum terms and conditions of non-discriminatory service, including functional unbundling. Order No. 888 required utilities that tendered for filing open access tariffs prior to the issuance of the Rule (Group 1 public utilities) to make section 206 compliance filings that

[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.

[504] *See AGD*, 824 F.2d at 1008.

[505] 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.

contain the non-rate terms and conditions set forth in the Open Access Rule pro forma tariff. That tariff expressly includes provisions allowing a transmission provider to seek to recover stranded costs in accordance with the terms, conditions and procedures set forth in Order No. 888. Of the 101 public utilities that had some version of open access available prior to Order No. 888, all now have open access tariffs on file that contain provisions that expressly allow the transmission provider to seek to recover stranded costs as provided in Order No. 888.

We also will decline San Francisco's request that the Commission include ''exercise of pre-existing contract rights for transmission and designation of wholesale loads'' or similar language as an example of a situation for which stranded costs may not be sought.[506] We are not prepared to make individual factual determinations in the context of this Rule.[507] As specific requests for stranded cost recovery are presented to the Commission, they will be addressed based on the facts presented and the merits of the particular request.

Rehearing Requests Seeking Broader Stranded Cost Recovery

In sharp contrast to the entities seeking rehearing of the Commission's decision to allow stranded cost recovery, other entities ask the Commission to expand the scope of the stranded cost recovery allowed by Order No. 888. Various entities ask that the scope of stranded cost recovery be expanded to include situations in which the departing customer does not take unbundled transmission from the former supplier and in which previously existing municipal utilities annex additional territory or otherwise expand.[508] These entities disagree with the Commission's analysis in Order No. 888 that the opportunity to seek recovery should be precluded in situations in which the departing wholesale customer ceases to purchase power from the utility but does not use the utility's transmission system to reach another supplier. The Commission excluded these situations because the costs would not be stranded as a result of the Commission's open access transmission requirement, but rather as a result of the exercise of a preexisting competitive option. The entities argue on rehearing that such costs are attributable to the Commission's efforts to restructure the wholesale power market. Several argue that there is no good policy reason for addressing stranded costs only where linked directly to the Open Access Rule or section 211 orders because a variety of federal actions, not just the Open Access Rule and section 211 orders, have created a competitive wholesale power market and the specter of stranded costs caused by customers departing their traditional utility. They contend that, but for the Commission's creation of a vibrant power market, EPAct, and other pre-Order No. 888 efforts by the Commission to expand transmission access, the preexisting options would not have been (and historically were not) exercised.

Puget argues that even when a departing customer can import its new power supply without using its former supplier's transmission system, it frequently will be the case that the power supply would not be available to the customer if open access transmission rules were not in place to permit that power to move from distant generators over intervening utilities' transmission facilities.[509]

EEI expresses concern that strict application of the ''but for open access'' test would create new incentives to evade stranded cost recovery.[510] According to EEI, the Rule would deny recovery for costs stranded pursuant to a voluntarily negotiated transmission service agreement, but would permit recovery if such agreement were ordered pursuant to FPA section 211. In this manner, EEI contends that the Rule will discourage parties from settling transmission disputes. It says that any transmission agreement negotiated under ''the threat'' of section 211 should be entitled to stranded cost recovery if providing service results in the stranding of legitimate and prudent costs.

PSE&G and Carolina P&L express concern that denying stranded cost recovery where the departing customer does not use the former supplier's transmission system will create an artificial incentive to build ''contract path'' lines designed to thwart stranded cost recovery. They maintain that the existence of alternative transmission paths should not be a bar to stranded cost recovery where the departing customer avails itself of the Commission's *Mobile-Sierra* finding permitting customers to challenge the terms of their contracts under the just and reasonable standard. They assert that, notwithstanding the availability of alternative transmission, the only way that the customer could have availed itself of the *Mobile-Sierra* finding was as a result of the Commission's Open Access Rule.

Several entities contend that the FPA's requirement of just and reasonable rates and the Fifth Amendment's requirement to avoid confiscation require the Commission to address stranded costs that result when a departing customer does not use the former supplier's transmission system or that result from municipal annexation.[511] According to Puget, the ultimate Constitutional test will be whether Order No. 888 will afford a fair overall return on all prudent utility investments under the Constitutional standards set forth by the Supreme Court.[512] Coalition for Economic Competition submits that, as was the case in the context of the unbundling of natural gas pipelines, the Commission cannot ignore stranded costs resulting from the unbundling of electric services and should acknowledge its Constitutional obligations to address the recovery of all stranded costs, including those that result from municipal expansion and those that result when a

[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).

[507] 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.

[512] 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.

customer does not obtain transmission services from its former supplier.

SC Public Service Authority also asks the Commission to allow the recovery of stranded costs that result from the loss of indirect customers (*e.g.*, customers of wholesale requirements customers). It argues that if such indirect customers can get access to a new source of power through open access tariffs, the requirements of the utility's direct customer will decrease, and the supplying utility will suffer stranded costs. SC Public Service Authority states that because of the nexus between open access and the departure of the indirect customer, utilities that suffer stranded costs in the event of the loss of an indirect customer should have an opportunity to recover those costs under the reasonable expectation standard.

A number of entities also ask the Commission to find that open access transmission and stranded cost recovery are necessary to accomplish the remedy ordered by the Commission and thus are not severable.[513] To this end, they submit that if the Commission's ability to provide for stranded cost recovery is reduced or substantially modified, public utilities should be able to withdraw filed tariffs or to file amended tariffs. It is their position that deletion or substantial change of the open access or stranded cost provisions by the Commission or by a court would vitiate the basis on which the Commission premised the Rule.

In an effort to ensure that stranded cost recovery procedures do not become a vehicle for lengthy and expensive litigation over whether there is a sufficient nexus to open access, several entities ask the Commission to place on the departing generation customers the burden to demonstrate the absence of a nexus between their actions and the availability of open access transmission under the Rule in those cases where: (i) the contract has no term or termination provision; (ii) the Commission issues an order under section 206 reducing the term of the contract; or (iii) there is legitimate municipalization.[514]

Commission Conclusion

We will deny the requests for rehearing that ask us to expand the scope of stranded cost recovery to include situations in which the departing customer does not take unbundled transmission from its former supplier but instead obtains transmission from another utility or obtains power from a third party supplier who is located in the customer's service territory and thus requires no transmission from the former supplier.[515] As the Commission stated in Order No. 888, the premise of the Rule is that where the former requirements supplier had a reasonable expectation of serving beyond the contract term and the customer uses the open access transmission tariff of its former requirements supplier to obtain power from a new generation supplier, the customer must pay the costs that were incurred on its behalf under the prior regulatory regime. The Rule is not intended, however, to apply to the recovery of costs associated with the normal risks of competition, such as self-generation, cogeneration, or loss of load, that do not arise from the new, accelerated availability of non-discriminatory open access transmission. If a customer leaves its utility supplier by exercising options that could have been undertaken prior to mandatory transmission under Order No. 888 or the Energy Policy Act, or that do not rely on access to the former seller's transmission (such as access to another power supplier through another utility's transmission system or self-generation), there is no direct nexus to Commission-mandated transmission access.

For example, if a customer is able to obtain power from a new supplier by using the transmission system of another utility, it is likely that the customer could have made these arrangements in the absence of the new open access rules. The new transmission provider would have had little incentive to deny transmission services to the customer in order to protect another utility's existing power supply arrangement, since it was not the customer's power supplier in the first place. As Order No. 888 suggested, it is likely that the neighboring utility would have a positive incentive to provide the transmission service in order to increase its transmission revenues, and that this incentive is unchanged by open access transmission.[516]

Although EEI and others argue that EPAct and the Commission's pre-Order No. 888 efforts to expand transmission access have facilitated the exercise of pre-existing competitive options, the fact remains that such options historically were available before open access. For this reason, we conclude that costs incurred as a result of the exercise of pre-existing competitive options do not fall within the scope of Order No. 888.

A number of entities argue that, even where the departing customer obtains access to another power supplier through the transmission system of another utility (*i.e.*, not that of its former supplier), the power supply would not have been available to the customer if open access transmission rules were not in place to permit that power to move from distant generators over intervening utilities' transmission facilities. Some argue that there is no good policy reason for addressing stranded costs only where linked directly to the Open Access Rule (or to a section 211 order) because a variety of federal actions have created a competitive wholesale power market and the specter of stranded costs caused by customers departing their traditional utility. While these arguments may have superficial appeal, the effective result would be to provide for recovery of stranded costs from departing customers under the Rule no matter how tenuous the nexus to Commission-mandated transmission access. The Commission has to exercise reasonable judgment and reasonable line drawing regarding the link between its actions in this Rule and the decision to allow an opportunity for extra-contractual stranded cost recovery from the departing customer. The Commission believes that requiring a direct nexus between Commission-mandated transmission access (namely, requiring that the departing customer obtain access to another power supplier *through the use of its former supplier's Commission-required tariff—i.e.*, an open access tariff or a tariff ordered pursuant to section 211) and the special stranded cost recovery procedures of this Rule is the most reasoned and supportable approach because it establishes a clear link between availability of the transmission tariff

[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.

and the decision of the customer to seek an alternative supplier.

With regard to potential stranded costs associated with situations that could have occurred prior to the Open Access Rule and prior to the Energy Policy Act (such as self-generation), under traditional ratemaking such costs (albeit not previously labeled as potential ''stranded'' costs) would in most cases be reallocated in the next rate case to remaining customers. The fact that this Rule does not permit a utility to seek recovery of these types of costs from the departing customer does not mean that the Commission may not, in appropriate circumstances, permit their recovery through traditional ratemaking means. However, many factors will influence cost recovery in the future, including whether the utility is selling at cost-based or market-based rates and the transitional period to more competitive bulk power markets. The Commission will address these matters on a case-by-case basis.

We do not agree with those commenters who contend that the Commission's failure in Order No. 888 to allow for the recovery of costs incurred by a utility when a departing customer does not use the former supplier's transmission system to reach a new supplier would be confiscatory in violation of the Constitution. As the Supreme Court explained in *Duquesne,* ''[t]he guiding principle has been that the Constitution protects utilities from being limited to a charge for their property serving the public which is so 'unjust' as to be confiscatory.''[517] However, Order No. 888 addresses only the recovery of legitimate, prudent and verifiable costs that are stranded if a former wholesale requirements customer or a former retail customer uses a Commission-mandated transmission tariff to reach a new supplier. As discussed above, Order No. 888 does *not* by its terms bar the recovery of costs that do not result from the use of Commission-required transmission access (*i.e.,* costs that result when a departing customer does not use the former supplying utility's open access tariff). Utilities may, as before, seek recovery of such non-open access-related costs on a case-by-case basis in individual rate proceedings. The Commission will not prejudge those issues here. As a result, the argument that the Commission's treatment of stranded costs in Order No. 888 (*i.e.*, its failure to treat certain costs as costs for which recovery may be sought under the Rule) will result in rates that will be so unjust as to be confiscatory is misplaced.

We deny SC Public Service Authority's request that the Commission allow a utility to seek recovery of stranded costs that result from the loss of indirect customers (*i.e.,* the loss of the utility's customer's customers). The Commission does not believe it is appropriate or feasible to allow a public utility (or a transmitting utility under section 211 of the FPA) to seek recovery of stranded costs from an indirect customer (*i.e.,* a customer of a wholesale requirements customer of the utility). The reasonable expectation analysis would apply only to the direct wholesale customer of the utility, not to the indirect customer. A utility may seek to recover stranded costs from a direct wholesale customer (subject to the requirements of the Rule), but it is up to the direct wholesale customer, through its contracts with its customers or through the appropriate regulatory authority, to seek to recover stranded costs from its customers.

We also deny PSE&G's and Carolina P&L's request that a utility be allowed to seek stranded cost recovery in cases where the departing customer uses the Commission's *Mobile-Sierra* finding to get out of the contract under the just and reasonable standard and uses alternative suppliers and alternative transmission.[518] We disagree with their argument that the only way that the customer could have availed itself of a *Mobile-Sierra* finding was as a result of the Commission's open access rules and thus the necessary nexus is met. A customer to a *Mobile-Sierra* contract always has the option of instituting a proceeding under section 206 of the FPA and making a showing of why, under *Mobile-Sierra,* it is in the public interest to modify the contract.

We will not, at this time, make any determination whether or not the requirements of open access transmission and stranded cost recovery are severable. As we indicated in Order No. 888, we issued the Stranded Cost Final Rule simultaneously with the Open Access Rule because we believe that the recovery of legitimate, prudent and verifiable stranded costs is critical to the successful transition of the electric industry to a competitive, open access environment.[519] We believe that our decision to allow stranded cost recovery will be upheld by the courts. Moreover, as we discuss in Section IV.A.1 above, it would be premature to consider at this time what the Commission would do if one or more of the provisions of the Rule are not upheld. Circumstances at the time of any court order would dictate how we should proceed and we would consider all such circumstances, and the entirety of our policy decisions, before determining how to respond to a court decision.

Further, we decline to place on departing generation customers the burden of demonstrating that no nexus exists between their actions and the availability of open access transmission under the Rule in cases involving no term or termination provision, an order under section 206 reducing the term of the contract, or municipalization. The proponents of such a proposal, Carolina P&L and PSE&G, attempt to justify it as a means to ensure that stranded cost recovery procedures do not become a vehicle for lengthy and expensive litigation over whether there is a sufficient nexus to open access in the three identified situations. However, Order No. 888 places the burden on the utility seeking stranded cost recovery to demonstrate that the costs for which it seeks recovery fall within the scope of the Rule and that it had a reasonable expectation of continuing service. In this regard, the Rule tracks the requirement of sections 205 and 206 of the FPA that a public utility demonstrate the justness and reasonableness of its proposed rates. Carolina P&L and PSE&G fail to explain why it would be appropriate for customers (as opposed to the utilities seeking recovery) in the three identified situations to bear the initial burden of demonstrating why costs should not be recovered from them under the Rule.[520] As a result, we reject their proposal.[521]

Rehearing Requests—Stranded Cost Recovery By Transmitting Utilities That Are Not Public Utilities

A number of entities contend that the Commission's decision to limit stranded cost recovery for transmitting utilities that are not public utilities to section

[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.

[521] 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.

211 proceedings is inconsistent with its decision to impose the reciprocity requirement on those utilities, violative of the principle of comparability, and unduly discriminatory and anticompetitive.[522] NRECA submits that if the Commission has the statutory authority to require non-public utilities to render transmission service outside of a section 211 proceeding through the reciprocity, RTG and power pool provisions of the Rule, then it must exercise that authority to ensure stranded cost recovery by such non-public utilities. Noting that the Rule does not address how a non-public utility that chooses voluntarily to provide an open access tariff can recover its stranded costs, SC Public Service Authority asks the Commission to confirm on rehearing that non-jurisdictional utilities can include a provision for recovery of stranded costs in their tariffs provided pursuant to the Final Rule.

Commission Conclusion

The Commission's jurisdiction over the recovery of stranded costs by non-public utilities, and thus our ability to permit an opportunity for recovery of such costs, is limited by statute. While we have the statutory authority to ensure that non-public utilities have the opportunity to seek recovery of stranded costs in proceedings under sections 211 and 212 of the FPA,[523] we do not have such authority under sections 205 and 206 of the FPA. However, we clarify that nothing in the Final Rule was intended to preclude non-public utilities from including stranded cost provisions in voluntary reciprocity tariffs or from otherwise recovering stranded costs under applicable law. We discuss these matters in detail below.

As we stated in Order No. 888 in response to commenters' objections that the Rule would give public utilities a greater opportunity than other transmitting utilities to recover stranded costs, our jurisdiction over transmitting utilities that are not also public utilities is limited. If the selling utility is a transmitting utility that is not a public utility, its power sales contracts are not subject to this Commission's jurisdiction under sections 205 and 206 of the FPA. Thus, we can provide such a transmitting utility an opportunity to recover stranded costs only through Commission-jurisdictional transmission rates fixed under sections 211 and 212 of the FPA.[524]

The open access tariff reciprocity provision, which applies to all open access customers that own, operate, or control transmission facilities or are affiliates of entities that own, operate or control such facilities, and that do not obtain a waiver of the provision, does not create jurisdiction for the Commission to fix the rates for these utilities. Contrary to the suggestions of some, the tariff reciprocity provision is not based on any statutory authority of the Commission to require non-public utilities to render transmission service outside of a section 211 proceeding. As we make clear in Order No. 888, we do not have authority under sections 205 and 206 of the FPA to require non-public utilities to file tariffs (or rate schedules for that matter) with the Commission.[525] In permitting a public utility to deny transmission service to any person that requests service under an open access tariff unless that person provides reciprocal non-discriminatory transmission services to the transmission provider, we are not acting under any statutory authority to require non-public utilities to provide transmission access. Rather, out of fairness, we are conditioning the use of open access services by all customers, including non-public utilities, on an agreement to offer comparable transmission services in return to the public utility transmission provider.[526]

We clarify that a non-public utility that chooses voluntarily to offer an open access tariff for purposes of demonstrating that it meets the reciprocity provision can include a stranded cost provision in its tariff. However, adjudication of any stranded cost claims under that tariff is not subject to the Commission's jurisdiction.[527] With the exception of our section 210 interconnection and sections 211–212 transmission rate jurisdiction, we do not have jurisdiction over the rates of non-public utilities. If a non-public utility wishes to recover stranded costs pursuant to a tariff or otherwise, it can seek to do so subject to the review of the appropriate regulatory authority.[528]

Rehearing Requests—Stranded Cost Recovery for Transmission Dependent Utilities

NRECA and TDU Systems challenge the Commission's decision not to guarantee a transmission dependent utility that is not a public utility stranded cost recovery when the transmission dependent utility's customers leave its system by using the open access tariff of another utility. They submit that the ability of transmission dependent utilities to compete with public utility transmission providers in an open access environment would be severely affected by their inability to recover stranded costs on a basis comparable to those transmission providers. They argue that the open access provisions of Order No. 888 will result in the stranding of costs incurred by non-transmission owning, non-public utilities to serve customers that depart to other suppliers. They contend that these customers are already located in close proximity to, and interconnected to, public utilities; thus it is likely that they would use the open access tariffs of these public utilities to obtain their new power supplies. NRECA and TDU Systems argue that this situation should meet the ''but for open access'' nexus. On this basis, they assert that Order No. 888 is no less the proximate cause of the departure of customers of transmission dependent utilities than it is of the departure of public utility transmission owners' customers. They object that the Commission takes no account of the anticompetitive effects of disregarding costs stranded on transmission dependent utilities' systems as a result of open access.

Dairyland Coop asks the Commission to recognize a generation and transmission (G&T) cooperative and its member distribution cooperatives as a single economic unit for purposes of stranded cost recovery (such that conversion of a distribution

[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.

[526] 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.

[528] 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).

cooperative's retail customer to a wholesale customer may result in stranded costs for the G&T cooperative). It objects that the Commission implicitly rejected comments to this effect without discussion in Order No. 888.

Commission Conclusion

We deny the requests for rehearing of our decision not to permit transmission dependent utilities and electric cooperatives to seek stranded cost recovery unless they are public utilities or transmitting utilities that would otherwise qualify under the Rule. With regard to transmission dependent utilities, as we indicated in Order No. 888, the limited opportunity for stranded cost recovery contained in the Rule would not likely apply in the case of transmission dependent utilities, who own little or no transmission and the majority of whom would not be public utilities or transmitting utilities subject to the Commission's jurisdiction.[529] The opportunity for extra-contractual wholesale stranded cost recovery is allowed only where the departing customers use open access (or section 211 access) on the transmission systems of their former generation suppliers and only for a discrete set of requirements contracts executed on or before July 11, 1994 that do not contain explicit stranded cost provisions (involving the bundled provision of generation and transmission) and retail-turned-wholesale situations for which the utility can demonstrate that it had a reasonable expectation of continuing service. Even though it may be the case that transmission dependent utilities lose generation customers that are able to use open access tariffs of other utilities to reach new suppliers, there was nothing to keep these other utilities from offering such transmission service before Order No. 888. These other utilities had no economic incentive to deny such service before Order No. 888. Thus, in the scenario posited in the rehearings, the transmission dependent utilities do not meet the fundamental premise of the Rule: that a utility that historically has supplied bundled generation and transmission services to a wholesale requirements customer and incurred costs to meet reasonably expected customer demand should have an opportunity to recover legitimate, prudent and verifiable costs that may be stranded because open access use of the utility's transmission system enables a generation customer to shop for power.[530]

However, this is not to say that a transmission dependent utility that is not a public utility, or other non-public utility entities (such as RUS-financed cooperatives), cannot seek recovery of the cost of any resulting uneconomic assets through their contracts with their customers or through the appropriate regulatory authority. The Commission has no objection to these entities being able to seek such cost recovery through the appropriate regulatory channels. However, because the Commission does not have jurisdiction over these entities (other than through sections 211 and 212 in the case of non-public utility transmitting utilities), it does not have authority to allow them to recover these costs.[531]

We also deny Dairyland Coop's request that the Commission recognize a G&T cooperative and its member distribution cooperatives as a single economic unit for purposes of stranded cost recovery. If a cooperative obtains its financing through RUS, it is not a public utility subject to our jurisdiction under sections 205 and 206 of the FPA. Although the Commission has no objection to these G&T cooperatives being able to seek cost recovery (including recovery of costs on behalf of their distribution cooperatives) through the appropriate regulatory channels, this Commission does not have authority to allow them to seek recovery of stranded costs unless access is obtained through a section 211 order.[532]

In the case of a G&T cooperative that is a public utility (of which there are just a handful at the present time), such a cooperative would have to have a jurisdictional wholesale requirements contract with its distribution cooperative in order to be able to seek recovery of stranded costs under the Rule. In the case of a jurisdictional G&T cooperative, the request that the G&T be treated as a single economic unit with the distribution cooperative (such that departure of a distribution cooperative's retail customer would be treated as resulting in stranded costs for the G&T cooperative for which the G&T could seek recovery) is, in effect, a request for recovery of stranded costs from an indirect customer. As we discuss above, the Commission does not believe it is appropriate or feasible to allow a public utility (or a transmitting utility under section 211 of the FPA) to seek recovery of stranded costs from an indirect customer (*i.e.*, a customer of a wholesale requirements customer of the utility) under this Rule. The reasonable expectation analysis would apply only to the direct wholesale customer of the utility, not to the indirect customer. It is up to the direct wholesale customer of the utility, through its contracts with its customers or through the appropriate regulatory authority, to seek to recover such costs from its customers.

Commenters have provided no basis for making an exception in the case of cooperatives. Moreover, to treat a G&T cooperative and its member distribution cooperatives as a single economic unit for stranded cost purposes would be inconsistent with the Commission's decision not to treat cooperatives as a single unit for purposes of Order No. 888's reciprocity provision.

In Order No. 888, in response to arguments raised by cooperatives, the Commission agreed to limit the reciprocity requirement to corporate affiliates. In other words, if a G&T cooperative seeks open access transmission service from the transmission provider, only the G&T cooperative (not its member distribution cooperatives) would be required to offer transmission service. If a member distribution cooperative itself receives transmission service from the transmission provider, then it (but not its G&T cooperative) must offer reciprocal transmission service over its interstate transmission facilities, if any.[533] Dairyland has provided no basis to support treating cooperatives differently for stranded cost purposes and reciprocity purposes. We accordingly will deny Dairyland's request for rehearing on this issue.

Rehearing Requests Opposing Limitation of Recovery to Wholesale Requirements Customers

PA Munis argues that it is inequitable and anticompetitive for ''wholesale requirements customers'' but not other ''wholesale customers'' to have to pay stranded costs, repeating an argument that it made in its comments on the supplemental stranded cost NOPR. It says that there is no difference in the firm power provided by public utilities

[529] FERC Stats. & Regs. at 31,790; *mimeo* at 456–57.

[530] 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.

to ''wholesale requirements customers'' and to ''wholesale customers'' and no difference in the generating facilities required and the costs of operation between the production of firm capacity and energy required for ''wholesale requirements sales'' and ''wholesale sales.'' PA Munis submits that the total amount of wholesale requirements power purchased in the United States is less than two percent of the total amount of firm power sales. It argues that requiring only wholesale requirements customers to pay stranded costs would restrict the ability of such customers to switch suppliers while not similarly restricting large firm wholesale customers. It contends that wholesale firm requirements customers therefore will not have equal access under the Rule because of the increased transmission rates for stranded costs that would not be levied on other large wholesale firm customers. Pa Munis says this produces the same result found unlawful in the *Maryland People's Counsel* case[534]—equal access to all wholesale customers is virtually denied by the chilling effect of stranded costs borne only by wholesale requirements customers.

Commission Conclusion

In Order No. 888, the Commission fully addressed the concerns of PA Munis. We again address below the major distinctions between requirements and other customers and deny rehearing.

In Order No. 888, we explained that the historical and practical relationship between a utility and its wholesale requirements customers, including the expectation of continued service, justifies allowing public utilities the opportunity to seek to recover the stranded costs covered by this Rule from only those customers and not from non-requirements customers that contract separately for transmission services to deliver their purchased power or from wholesale customers that purchase non-requirements power. Requirements customers historically were long-term customers who by definition depended upon their local suppliers because they were captive customers. Utilities had no obligation to provide transmission service that would allow these customers to reach other suppliers, and there were no other transmission facilities in proximity to those of the supplying utility. And the service involved requirements power; that is, these customers were dependent upon the wholesale supplier for all or part of their power. Utilities thus assumed they would continue serving these customers and may have made significant investments based on that long-term expectation. These same assumptions cannot be made for short-term, non-firm transactions and other wholesale non-requirements firm transactions. Unlike requirements customers, these customers had other options. Thus, the supplying utility could not assume that these customers would remain on its system.

With regard to short-term transactions, utilities did not (and do not today) generally make investments for short-term economy-type transactions. Rather, such transactions were entered into only when the utility temporarily had available capacity or energy that could be provided to the buyer at a price higher than the seller's incremental cost and lower than the buyer's decremental cost. The utility was not obligated in any way—either explicitly or implicitly—to provide for the needs of coordination customers. Because coordination transactions were not the cause of stranded investment decisions, it would be inappropriate to allocate such costs to non-requirements customers.[535]

With regard to long-term, non-requirements firm transactions, such as unit power sales contracts, we note that there was no implied obligation to serve customers to these transactions as there was for requirements customers. Generating units were not built for the purpose of entering into these arrangements. Therefore, because utilities did not incur costs on behalf of non-requirements firm power sales customers, such customers have not caused costs to be stranded and should not be required to pay stranded cost charges. Accordingly, we reaffirm limiting the opportunity for stranded cost recovery to costs associated with wholesale requirements contracts.[536]

We recognize PA Munis' concern that if a utility meets the evidentiary requirements of the Rule and is allowed to recover stranded costs from wholesale requirements customers, such customers may see little or no savings *in the short-term* by switching power suppliers, since a stranded cost charge (in the form of either an exit fee or a surcharge on transmission) would be paid in addition to the power price paid a new supplier. However, as we discuss above and in Section IV.J.2 below, we believe that stranded costs are transition costs that must be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets. Further, as we explain in Section IV.J.3 below, although spreading the costs to all transmission users of a utility's system (rather than imposing them directly on the departing wholesale requirements customer) might enable the customer to see earlier power cost savings than would result if stranded costs were directly assigned to the customer, we have concluded that this potential benefit to a broad-based approach is outweighed by a significant countervailing disadvantage—namely, the violation of the cost-causation principle of ratemaking. The Commission rejects a broad-based approach for the electric industry primarily because the potential power cost savings to the departing generation customer would be realized only by shifting costs that are directly attributable to the departing generation customer to the other users of the utility's transmission system.

Contrary to PA Munis's claim, we believe that the circumstances surrounding the opportunity to seek stranded cost recovery from wholesale requirements customers that is permitted in Order No. 888 are distinguishable from the issues that were before the court in the *Maryland People's Counsel* cases. Those cases involved challenges to Commission orders that permitted pipelines to transport gas at lowered prices to ''non-captive consumers'' (large industrial end users capable of switching to alternative fuels) without any obligation to provide the same service to ''captive consumers'' such as local distribution companies and their residential customers. In *Maryland People's Counsel I*, the court invalidated the Commission's authorization of a ''special marketing program'' under which a pipeline and its producer would agree to amend their high-priced gas purchase contract to permit the producer to sell the committed gas elsewhere at market prices and to credit the volume of such sales against the pipeline's high-priced purchase obligations. Eligibility to purchase the

[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.

cheaper released gas was limited to industrial users. The court found that the Commission had failed to provide a reasonable basis for its decision to exclude ''captive customers'' from eligibility to purchase the cheaper released gas.[537] In *Maryland People's Counsel II*, the court invalidated the Commission's approval of blanket authority for interstate transportation of natural gas sold directly by producers to fuel-switchable end users. The court held that the Commission had failed to consider the anticompetitive effects of failing to require the pipelines to provide the same service to captive consumers on nondiscriminatory terms.[538]

In contrast to the *Maryland People's Counsel* cases, the Commission in Order No. 888 is not discounting services for one class of customers to the exclusion of another, nor is it ordering that public utilities provide transmission access to only a specified customer group. To the contrary, Order No. 888 requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to provide open access transmission to any ''eligible customer,'' with ''eligible customer'' defined broadly to include ''any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale.'' [539] Among other things, Order No. 888 gives wholesale requirements customers that previously were captive customers of their public utility suppliers the opportunity at the expiration of their contracts to take unbundled transmission service from their former suppliers in order to reach new suppliers. At the same time, the Commission recognizes that the departure of a wholesale requirements customer in this circumstance may strand costs that the former supplying utility incurred based on a reasonable expectation that it would continue to serve the customer beyond the contract term. As a result, Order No. 888 gives the former supplying utility the *opportunity* to seek recovery of costs stranded by the wholesale requirements customer's departure.

In further contrast to the *Maryland People's Counsel* cases, the Commission addresses in this Order (above) PA Munis' claim that it is inequitable and anticompetitive that only wholesale requirements customers and not other wholesale customers are subject to the stranded cost provisions of Order No. 888. The Commission has explained in detail the rationale for its decision that public utilities should be allowed an opportunity to seek to recover the stranded costs covered by this Rule only from wholesale requirements customers. The Commission has also addressed in Section IV.J.2 below the concerns expressed by some as to the potential anticompetitive effect of stranded cost charges.

Rehearing Request—ERCOT

The TX Com [540] asks the Commission to clarify that ERCOT utilities may not use a section 211 proceeding as a vehicle to obtain wholesale or retail stranded cost recovery. [541] It notes that based on the definitions in section 35.26 of ''wholesale stranded cost'' [542] and ''wholesale transmission service,'' [543] the Rule applies only to interstate service and does not apply to the intrastate service provided by the utilities within ERCOT, yet the Commission suggests that it might permit a utility in ERCOT to recover stranded costs in a section 211 proceeding. Even if the Commission concludes that it has the authority to resolve stranded cost issues for ERCOT utilities, TX Com asks the Commission to establish a preference for resolution of transmission and stranded cost issues in ERCOT by TX Com. It suggests that uncertainty and gaming as to the choice of a forum could be avoided by executing a Memorandum of Understanding between TX Com and the Commission that would require interested persons to submit disputes to TX Com. Further, to the extent that the new ERCOT transmission access rules adopted by the TX Com may be deemed as the cause of stranded costs in ERCOT, TX Com asserts that it should be allowed to resolve issues related to such stranded costs.

Commission Conclusion

In *City of College Station, Texas*,[544] the Commission repeated its view, first articulated in 1979, that sections 211 and 212 of the FPA clearly give the Commission jurisdiction to order transmission services within ERCOT, subject to the special rate provision for ERCOT utilities in section 212(k).[545] The Commission indicated that if it issues a final order in that case setting rates for transmission services within ERCOT, it will comply with section 212(k) and give deference to the TX Com's ratemaking methodology insofar as practicable and consistent with section 212(a).

Our jurisdiction to order transmission services within ERCOT includes the authority to address costs that are stranded by a section 211 transmission order.[546] Consistent with the special rate provision in section 212(k), we clarify

[537] *See* 761 F.2d 768.

[538] *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.

[541] 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.

[542] ''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.

[543] ''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).

[545] 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).''

that we will give deference to the TX Com's ratemaking methodology, including any provisions or procedures related to stranded cost recovery, insofar as it is practicable and consistent with section 212(a) and consistent with the principle of comparability set out in Order No. 888.

2. Cajun Electric Power Cooperative, Inc. v. FERC [547]

In Order No. 888, the Commission explained why it does not interpret the *Cajun* court decision as barring the recovery of stranded costs and why the record developed in this generic proceeding fully addresses the court's concerns regarding meaningful access to alternative suppliers.[548]

We also addressed the court's concern that the method of recovery in that case (a charge in the departing customer's transmission rate) might constitute an anticompetitive tying arrangement. We explained that the stranded cost recovery procedure we prescribe in the Open Access Rule is only a transitional mechanism that is intended to enable utilities to recover costs prudently incurred under a different regulatory regime. The purpose and effect of the stranded cost recovery mechanism that we approved in the Rule is to facilitate the transition to competitive wholesale power markets. We concluded that while stranded cost recovery may temporarily delay some of the benefits of competitive bulk power markets for some customers, such transition costs must be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets.

In reaching these conclusions, the Commission applied the traditional regulatory concept of cost causation. We stated that it is not an illegal tying arrangement to hold a customer accountable for the cost consequence of leaving an incumbent supplier if, under our rules, the incumbent supplier must show a reasonable expectation of providing continuing service to that customer before it can recover stranded costs from the customer.

In addition, in response to the *Cajun* court and commenters in this proceeding as to the need to provide as much certainty as possible for departing customers concerning their potential stranded cost obligation, the Commission included a formula for calculating a departing customer's potential stranded cost obligation. We explained that the revenues lost formula is designed to provide certainty for departing customers and to create incentives for the parties to address stranded cost claims between themselves without resort to litigation.

Rehearing Requests Arguing That the Commission Has Not Resolved the Cajun Court's Concerns

Several entities submit that the Commission has not resolved the *Cajun* court's tying concerns. They argue that tying arrangements are still the essence of the stranded cost recovery method mandated by Order No. 888, and that a tying arrangement is a *per se* antitrust violation that is not subject to justification by reference to the reasons for the restraint or the expected ancillary benefits.[549] A number of these entities object that the Commission does not address the court's substantive concern that a stranded cost provision is the antithesis of competition.[550] Several object that the Commission brushes aside the acknowledged anticompetitive effects of the rule as being ''transitional only,'' suggesting that short-term anticompetitive impacts are acceptable as long as the Commission is doing something that will be good for customers in the long term.[551] They also contend that the anticompetitive effects would not be limited to a transitional period, or that the transitional period could last indefinitely, thereby diluting or even nullifying the benefits of competition for years to come.[552]

Several entities submit that the Commission erred in concluding that the stranded cost rules contained in Order No. 888 would allow customers ''meaningful'' access to alternative power suppliers.[553] Among other things, these entities contend that there is no showing in the Order that transmission providers will not continue to exercise monopoly power over their transmission systems and that competition in generation will not be stifled by the stranded cost recovery mechanism.

Some entities also object that the stranded cost procedures contained in Order No. 888 fail to provide certainty in the computation of recoverable stranded costs. They argue that the prospect of stranded cost liability and related litigation add costs of potential deal-killing magnitude to any power supply acquisition considered by a customer.[554]

APPA and ELCON challenge the Commission's description of *Western Resources, Inc.* v. *FERC* [555] as affirming the Commission's ability to allow stranded cost recovery. APPA argues that *Western Resources* does not justify the stranded cost provisions of Order No. 888 because it was a filed rate doctrine case, not a stranded cost case. APPA says that *Western Resources* involved no consideration of any allegation of anticompetitive conduct and no allegation that the utilities' proposal constituted an illegal tying arrangement.

Commission Conclusion

We will deny the requests for rehearing advanced on the basis of the *Cajun* case. We disagree with those entities that contend that the Commission has not resolved the *Cajun* court's tying concerns. As an initial matter, we note that the parties that have raised this issue on rehearing ignore the fact that while this Commission has a responsibility to consider the anticompetitive effects of regulated aspects of interstate utility operations,[556] it has other statutory and regulatory public interest considerations which it must balance in order to engage in reasoned decisionmaking. In this proceeding, we have carefully balanced our responsibilities to remedy undue discrimination and to consider anticompetitive effects, our goal to eliminate market power of utilities and anticompetitive effects in the long run, and the need to provide a transition to competitive markets that is fair, that maintains a stable electric utility industry, and that recognizes the obligations incurred in a past, non-competitive regulatory regime. As discussed below, we do not believe that the stranded cost proposal adopted in the Rule results in an illegal tying arrangement, as argued on rehearing. We believe we have given reasoned consideration to any potential transitory

[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.

[550] *E.g.,* Central Illinois Light, American Forest & Paper.

[551] *E.g.,* American Forest & Paper, PA Munis.

[552] *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).

anticompetitive effects of our stranded cost policy and that we have met the directives of the court in *Cajun*.

In considering the *Cajun* decision, it is important to note that the *Cajun* court assumes the presence of a competitive market in the electric utility industry, but such a competitive market does not now exist. Instead, the Commission is in the process of trying to bring about a competitive market and to manage the transition thereto.[557] When the Commission undertook a similar restructuring in the gas industry, the D.C. Circuit invalidated the Commission's efforts precisely because the Commission had failed to deal with the stranded cost problem in a satisfactory manner.[558]

As we indicated in Order No. 888, we do not believe it is an illegal tying arrangement to hold a customer accountable for the consequences of leaving an incumbent supplier if, before the incumbent supplier can recover legitimate, prudent and verifiable stranded costs from the departing customer, it must show that it incurred costs to provide service to the customer based on a reasonable expectation of continuing to serve the customer. Order No. 888 provides no guarantee of stranded cost recovery. Moreover, Order No. 888 provides the opportunity to recover stranded costs only for a discrete set of wholesale requirements contracts—those executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision—and for retail-turned-wholesale customers. Thus, it is not necessarily the case that customers will have to pay stranded costs when they leave their current suppliers. To the contrary, before a utility can recover stranded costs from a customer, the utility must overcome certain evidentiary hurdles (including a rebuttable presumption of no reasonable expectation of continuing service if the contract contains a notice of termination provision). Particularly given the narrowly tailored circumstances under which stranded cost recovery is permissible under the Rule, we do not view it as the antithesis of competition.

We dismiss as misplaced the claims that Order No. 888's stranded cost recovery mechanism is a tying arrangement that is a *per se* antitrust violation that cannot be justified by reference to the reasons for the restraint or the expected ancillary benefits. Any "tying" that might result from the Rule is by regulatory order, *not* through monopoly power, and is justified as a means to avoid unfair cost shifting and to achieve the pro-competitive benefits of the Rule. As we stated in Order No. 888, the purpose and effect of the stranded cost recovery mechanism that we approve are to facilitate the transition to competitive wholesale power markets, *not* to prevent a generation customer of a utility from being able to reach alternative suppliers through its former supplier's transmission.[559]

To be sure, imposing a stranded cost charge might, in the short run, make some customers indifferent to whether they stay with their current suppliers and avoid stranded costs, or go with new suppliers but pay stranded costs to the former suppliers.[560] There is no question that, without the stranded cost recovery mechanism, some customers would be far more likely to switch to lower-cost suppliers and enjoy sooner the benefits of a competitive power market. But, as detailed in Order No. 888, such an approach may result in higher costs for other customers. We thus have had to balance the potential for earlier benefits for some customers against other public interest considerations, most particularly the need to provide a fair mechanism by which utilities can recover the costs of past investments under traditional regulatory concepts of prudently incurred costs and cost causation. The result is not to deny competitive advantages, but only to delay their full realization for some customers.

In any event, we do not believe that the Commission-imposed mechanism of allowing the utility to recover stranded costs from the departing customer through its transmission rates falls within the category of an illegal tying arrangement under the antitrust laws. As the Supreme Court has defined it, "[a] tying arrangement is 'an agreement by a party to sell one product but only on the condition that the buyer also purchases a different (or tied) product, or at least agrees that he will not purchase that product from any other supplier.'"[561]

Here there is no "tying" of "products."[562] Instead, the Rule provides a mechanism for recovering costs associated with a prior contract. We have not adopted a rule under which a customer may purchase transmission from a utility only on the condition that the customer also purchases a different product, namely, power, from the utility.[563] To the contrary, the Commission, through the Order No. 888 open access transmission requirement, is attempting to provide the customer with the opportunity to obtain unbundled transmission from a former supplying utility as a means to reach a new generation supplier. Whatever else, the stranded costs are not charges for "products" and thus there is no "tying" in the conventional sense. At best, there is only a condition: in obtaining unbundled transmission, the customer must also pay appropriate costs stranded by its use of Commission-required transmission access.

Finally, it is not clear how often departing customers will be obligated to pay stranded costs. Stranded cost recovery is by no means guaranteed under the Rule, nor is it clear what portion of a utility's uneconomic investment will be recoverable as stranded costs. Even when a utility is able to meet the evidentiary standard and the Commission approves imposition of a stranded cost charge, the customer is free to pay off its obligation immediately. If it chooses to pay off the stranded cost obligation over time, that charge would not be imposed indefinitely on the customer. We have limited the scope of contracts and costs for which utilities may seek stranded cost recovery. This limitation—to certain contracts and demonstrated costs—in our judgment fairly allocates between utility and customer the

[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.

[558] *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.

[563] 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."

burdens and benefits of open access transmission.

Nor is it true that the Rule does not allow customers ''meaningful'' access to alternative power suppliers. The Final Rule pro forma tariff contains terms and conditions ensuring the provision of non-discriminatory transmission service. The requirements that a public utility take service under its own tariff for wholesale sales and purchases, adopt a non-discriminatory transmission information network, and separate power marketing and transmission functions further ensure non-discrimination and remove constraints to fair competition. The result is meaningful access to alternative suppliers that goes far beyond what was offered in the transmission tariff under review in *Cajun*.

Contrary to the claims of some, the Open Access Rule does not guarantee that a utility may sell its power at market-based rates. The open access compliance tariff required by Order No. 888 does mitigate transmission market power.[564] However, the Commission's Rule does not generically grant market-based rate authority to utilities that file compliance tariffs. Utilities must still demonstrate on a case-by-case basis that they not only have mitigated transmission market power but also do not have market power in generation[565] or other barriers to entry.

Notwithstanding the objections by some commenters that the stranded cost procedures of Order No. 888 fail to provide certainty in the computation of stranded cost charges, we believe that directly assigning stranded costs to departing generation customers using the revenues lost formula is the fairest and most efficient way to balance the competing interests of those involved. The alternatives that we considered (an up-front broad-based approach or an as-realized broad-based approach) have significant disadvantages and are extensively discussed in Order No. 888.[566] Following a careful evaluation of the alternatives, we concluded that a revenues lost formula to calculate a customer's stranded cost obligation is more reasonable and provides greater certainty than would other approaches, such as those that rely on broad-based surcharge schemes that impose costs that may never be incurred or those that result in widely fluctuating transmission rates.[567] As we stated in Order No. 888, while we recognize that some commenters oppose the revenues lost approach as imprecise, any ratemaking method that relies on estimates will be subject to forecasting error.[568] Nevertheless, we have gone to great lengths to provide specificity with respect to the calculation of the components of the formula.

In response to those commenters that argue that Order No. 888's stranded cost procedures will add costs of potential deal-killing magnitude to any power supply acquisition considered by a customer, we believe that, to the contrary, use of the formula will narrow the scope of disputes over the calculation of stranded costs, lend precision to the stranded cost amount it produces, and provide certainty to departing generation customers with respect to their stranded cost obligations.

APPA and ELCON object to the Commission's reference to *Western Resources* as a case affirming the Commission's ability to allow stranded cost recovery. Notwithstanding their efforts to distinguish *Western Resources* (for example, as a filed rate doctrine case, not a stranded cost case, and as a case involving no allegation of anticompetitive conduct), they have failed to make a convincing argument that our description of that case as ''confirm[ing] the validity of Commission-imposed stranded cost recovery mechanisms in the transition to competitive markets''[569] is not accurate. The case depends upon the validity of the Commission's decision to allow the recovery of costs stranded in the transition of the natural gas industry to a competitive market and supports the Commission's ability to allow stranded cost recovery in general. The same court, in *United Distribution Companies*, has recently confirmed the Commission's ability to allow the recovery of costs stranded in the transition to competitive markets, limiting its concerns to issues about ''how'' stranded costs should be recovered and from whom.[570]

3. Responsibility for Wholesale Stranded Costs (Whether To Adopt Direct Assignment to Departing Customers)

In Order No. 888, the Commission concluded that direct assignment of stranded costs to the departing wholesale generation customer through either an exit fee[571] or a surcharge on transmission is the appropriate method for recovery of such costs. We concluded that the departing generation customer (and not the remaining generation or transmission customers or shareholders) should bear the legitimate and prudent obligations that the utility undertook on that customer's behalf. In reaching this decision, we carefully weighed the arguments supporting direct assignment of stranded costs against those supporting the broad-based approach of spreading stranded costs to all transmission users of a utility's system. After a detailed review of the advantages and disadvantages of each approach, we concluded that, on balance, direct assignment is the preferable approach for both legal and policy reasons.[572] Our primary considerations were that direct assignment is consistent with the well-established principle that the one who has caused a cost to be incurred should pay that cost and that it will result in a more accurate determination of a utility's stranded costs than would an up-front, broad-based transmission surcharge.

The Commission also acknowledged that the direct assignment approach adopted in Order No. 888 is different from the approach taken for the natural

[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).

[565] A seller requesting market-based rates is not required 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.

[567] 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.

[568] FERC Stats. & Regs. at 31,841; *mimeo* at 600–01.

[569] FERC Stats. & Regs. at 31,793; *mimeo* at 464–65.

[570] 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.)

[572] FERC Stats. & Regs. at 31,797–800; *mimeo* at 477–85.

gas industry. We explained why we believe that difference to be justified by pointing out a number of differences between the transition of the electric industry to an open transmission access, competitive industry and the transition of the natural gas industry to open access transportation service by interstate natural gas pipelines.[573] We also declined to require a utility seeking stranded cost recovery to shoulder a portion of its stranded costs on the basis that such a requirement would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs, and explained why we applied a different approach in the gas area.[574]

Rehearing Requests Opposing Full Recovery From Departing Customers

A number of entities submit that the Commission has not adequately explained its decision not to require some utility sharing of stranded costs when the utility can satisfy the reasonable expectation criteria. They object that the Commission did not meaningfully consider the arguments made by commenters concerning utility responsibility (such as poor management decisions) for stranded costs.[575]

ELCON argues that departing customers are not the sole cause of stranded costs. IL Industrials submits that the statement in the Rule that utility shareholders ''had no responsibility for causing the legitimate, prudent and verifiable costs to be incurred'' is untrue.[576] It argues that although utilities may have had a legal obligation to serve and meet projected demands, how the utility chose to meet those obligations was under the utility's control. IL Industrials asserts that shareholders should bear some of the risk associated with the decisions of their management that were less than optimal. At a minimum, IL Industrials argues that the Commission should consider on a case-by-case basis (when it determines whether a utility has incurred legitimate and verifiable stranded costs) whether some amount of stranded costs should be shared with shareholders.

NASUCA challenges the Commission's statement in Order No. 888 that requiring a utility to shoulder a portion of its stranded costs ''would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.'' [577] It contends that there is no constitutionally guaranteed right of recovery of all prudent investment.[578] NASUCA further asserts that full recovery of uneconomic investment is not the norm. It submits that the Commission has rejected utility demands for full recovery of cancelled electric generation facilities.[579]

San Francisco cites *Market Street* as support for the proposition that the risk of unmarketability should fall, in whole or in part, on utility shareholders who knew of competitive risks and who have been compensated for those risks through rates of return.

A number of parties object that the Commission, in declining to require some shareholder sharing of stranded costs, is allowing the electric utility industry to claim more generous recoveries under Order No. 888 than it allowed the gas industry, and that it has provided no adequate rationale for this difference in treatment.[580] San Francisco states that although the Rule attempts to distinguish shareholder sharing in the natural gas industry ''as an extraordinary measure given the nature of the take-or-pay problem and the prevailing environment at that time,'' [581] the Commission has not identified how the nature of the take-or-pay problem was any more ''extraordinary'' than the nature of stranded costs in electric restructuring, or explain its reference to ''the prevailing environment at that time.''

Occidental Chemical submits that the Commission's decision not to allocate a portion of stranded costs to utilities on cost causation grounds contradicts the Commission's actions in Order No. 636, in which it required interruptible and new shippers, as beneficiaries of open access, to share in the costs of the transition.[582] Central Illinois Light states that the Commission should allow partial recovery of stranded costs and thereby correct key differences in the Commission's responses to gas and electric transition costs.[583]

Occidental Chemical also objects that the Commission failed to address the merits of its suggestion that the Commission grant a utility a presumption of prudence in return for absorbing a percentage of its stranded costs.

ELCON, in a supplement to its rehearing request,[584] submits that the D.C. Circuit's remand in *United Distribution Companies* of the aspect of Order No. 636 that allocated 100 percent of gas supply realignment costs to customers and none to pipelines has implications for the Commission's decision in Order No. 888 to allocate 100 percent of stranded costs to departing customers without any shareholder sharing of the costs. ELCON suggests that although the D.C. Circuit indicated that a finding of threat to the financial viability of the pipeline sector might justify such allocation, there is no evidence in the record in the Order No. 888 proceeding, and the Commission has made no finding, that wholesale stranded cost recovery jeopardizes the financial viability of the utility sector. It

[573] FERC Stats. & Regs. at 31,800–802; *mimeo* at 485–90.

[574] FERC Stats. & Regs. at 31,802–03; *mimeo* at 490–92.

[575] *E.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] FERC Stats. & Regs. at 31,802; *mimeo* at 490.

[578] 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).

[579] 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.

[581] 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.

[583] 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. § 825l(a).

adds that, to the extent the Commission relies on strict cost causation principles in Order No. 888, 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.

Commission Conclusion

As we explained in Order No. 888, we decided not to require a utility meeting the requirements for stranded cost recovery to shoulder a portion of its stranded costs because such a requirement would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.[585] Our decision (which allows assignment of legitimate, prudent and verifiable stranded costs to departing requirements generation customers, not to shareholders or other customers of the utility) also follows the cost causation principle that has been fundamental to our regulation since 1935.[586] It is important, in this regard, to distinguish between assuring recovery of all uneconomic costs (which Order No. 888 does not do) and providing an opportunity for recovery where the evidentiary requirements of the Rule are met.

Allowing full recovery of stranded costs under Order No. 888 is not equivalent to allowing 100 percent recovery of the costs of all uneconomic assets. A utility may have uneconomic assets for a variety of reasons, including a decline in load, customer shifts to natural gas, customer energy conservation, loss of a large industrial customer, customer self-generation, and a customer gaining transmission access through another utility's transmission system. The Rule does not provide for the recovery of the costs of such uneconomic assets.

Instead, the Rule defines a discrete set of uneconomic costs that are stranded by FPA section 211 or Order No. 888 transmission service (when a customer uses the former supplying utility's transmission system to reach a new supplier) for which utilities may seek recovery. However, even as to this set of costs the Rule does not *guarantee* 100 percent recovery. To be eligible to recover such costs, a utility must satisfy the reasonable expectation test set forth in Order No. 888. Even then, the utility will be eligible to recover only costs that are legitimate, prudent and verifiable.

In response to those entities that argue that departing customers are not the sole cause of stranded costs and that poor management decisions may be partly to blame, we reiterate that a determination that a utility has a reasonable expectation of continuing to serve a customer would not, in all circumstances, mean that costs incurred by the utility were prudent. As we said in Order No. 888, we cannot make a blanket assumption that all claimed stranded costs were prudently incurred. We explained that prudence of costs, depending upon the facts in a specific case, may include different things, such as prudence in operation and maintenance of a plant, and the utility's ongoing obligation to exercise prudence in retaining existing investments and power purchase contracts and in entering into new ones.[587] We clarified, however, that we do not intend to relitigate the prudence of costs previously recovered.

Thus, to the extent that costs have not been previously recovered by a utility, and depending upon the facts presented, a customer from whom a utility is seeking to recover stranded costs may be able to challenge the prudence of those costs. If such prudence challenge is successful, then the utility would not be entitled to recovery of the imprudently incurred costs, through stranded cost recovery or otherwise. We believe that this fully addresses the concerns of those entities that contend that departing customers should not be responsible for costs that result from poor management decisions or other actions by the utility.[588]

As we explained in Order No. 888, our decision not to require utilities to shoulder a portion of their stranded costs is based on the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.[589] NASUCA's reliance on the Commission's cancelled plant policy to support its argument that full recovery of uneconomic investment is not the norm is misplaced. The Commission's cancelled plant policy, which allows a utility to recover 50 percent of its prudently-incurred investment in a cancelled or abandoned plant, relates only to plants that are cancelled or abandoned prior to entering commercial service and thus prior to becoming used and useful.[590] The Commission has taken a different approach in the case of electric generating plants that are prematurely shut down after having been in commercial operation for a number of years. In the latter instance (which more closely resembles the type of costs for which a utility might seek recovery under Order No. 888 than does the cancelled plant before operation scenario), the Commission has allowed 100 percent recovery of prudently-incurred unamortized investment.[591]

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[585] FERC Stats. & Regs. at 31,802; *mimeo* at 490–91.

[586] 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).

[590] 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).

[591] 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

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San Francisco's and NASUCA's reliance on *Market Street* is also distinguishable. That case involved an industry (street railway) that had been rendered economically obsolete by market forces. The electric industry today, in contrast, is clearly not obsolete. Moreover, the costs that Order No. 888 gives a utility an opportunity to recover even in the face of market forces would not become stranded but for statutory and regulatory changes.

A number of parties contend that the Commission has not provided an adequate rationale for its different treatment of shareholder sharing in the natural gas industry. ELCON also relies on the D.C. Circuit's remand in *United Distribution Companies* of Order No. 636's holding that pipelines could recover 100 percent of their gas supply realignment (GSR) costs. After further review of this matter in light of the Court's decision in *United Distribution Companies*, we reaffirm that, even though the Commission permitted pipelines to recover take-or-pay costs based on ''cost spreading'' and ''value of service'' principles, stranded electric utility costs should be recovered based on traditional cost causation principles. This is because, despite the fact that both sets of costs are incurred in connection with a transition to unbundled, open access service, there are also substantial differences between the circumstances surrounding the two industries' incurrence of their respective transition costs.

The pipelines' take-or-pay problems began before the Commission initiated open access transportation in Order No. 436. The severe gas shortages of the 1970s led to enactment of the Natural Gas Policy Act (NGPA), which initiated a phased decontrol of most new gas prices and established ceiling prices for controlled gas, including incentive prices for price-controlled new gas higher than the ceiling prices previously established by the Commission under the NGA.[592] To avoid future shortages, pipelines then entered into long-term take-or-pay contracts at the high prices made possible by the NGPA, and those high prices stimulated producers to greatly increase exploration and drilling.[593] When demand unexpectedly fell and supply increased, the pipelines found themselves contractually bound to take or pay for high-priced gas which they could not sell. Even before Order No. 436 issued in October 1985, pipeline take-or-pay exposure was approaching $10 billion.[594] In 1986, as pipelines were just beginning to implement open access transportation under Order No. 436 and before the August 1987 issuance of Order No. 500, the pipelines' outstanding unresolved take-or-pay liabilities peaked at $10.7 billion.[595]

The Commission and the industry had never previously faced a take-or-pay problem of this nature or magnitude. In earlier times, pipelines had made take-or-pay payments to particular producers, and the Commission had a policy of permitting such payments to be included in rate base and then recovered as a gas cost when the pipeline later took the gas under make-up provisions in the contract.[596] By 1983, however, the pipelines could not manage their take-or-pay problems, and stopped honoring the bulk of their take-or-pay liabilities.[597] They then sought settlements with the producers to reform or terminate the uneconomic take-or-pay contracts and to resolve outstanding take-or-pay liabilities. Because pipelines had never previously incurred significant take-or-pay settlement costs, the Commission had no policy concerning whether and how pipelines were to recover those costs. The Commission commenced establishing such a policy in an April 1985 policy statement,[598] just six months before Order No. 436. When Order No. 500 issued, few take-or-pay settlement costs had yet been included in pipelines' rates. However, since the pipelines' outstanding take-or-pay liabilities were in the neighborhood of $10 billion, it was clear that pipelines would incur massive costs in their settlements with producers.

In short, when the Commission first addressed the issue of how to allocate take-or-pay settlement costs in Order No. 500, it did so under the shadow of the pipelines' vast outstanding take-or-pay exposure. The essential problem, therefore, was to decide which customers' rates should be raised to reflect the billions of dollars of take-or-pay settlement costs that the pipelines were incurring, but that the pipelines had still not filed to recover. To have allocated those costs solely to any one segment of the industry would have imposed a crushing new burden on that segment. For example, if the Commission had allocated the take-or-pay settlement costs entirely to bundled sales customers who chose to convert to transportation-only service, those customers would have ended up far worse off than if they remained as bundled sales customers.

As a result of all these facts, the fundamental premise of Order No. 500 was, as the Court expressed it in *KN Energy*, that ''the extraordinary nature of this problem requires the aid of the entire industry to solve it.'' [599] In order to accomplish this result, Order No. 500 established an equitable sharing mechanism for pipelines to use in recovering their take-or-pay settlement costs as an alternative to recovery through their commodity sales rates. Relying on ''cost spreading'' and ''value of service'' principles, the Commission permitted pipelines to allocate their take-or-pay settlement costs among all the pipelines' customers. The Commission also required the pipelines using the equitable sharing mechanism to absorb a portion of the costs in return for the ability to recover an equal portion through a fixed charge. Importantly, pipelines using the equitable sharing mechanism and agreeing to absorb a portion of the costs were given a presumption that their take-or-pay settlement costs were prudent. Those who did not choose to avail themselves of the sharing/absorption mechanism could still file for recovery of take-or-pay costs pursuant to the traditional ratemaking methodology. Because the pipelines' cash flow problems were so severe and they could not reasonably expect to recover their costs through their sales

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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).

[593] *Id.* at 31,509–10.

[594] *Id.* at 31,513.

[595] *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).

[597] 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.

[598] 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).

rates, they readily availed themselves of the special mechanism, with its presumption of prudence, rather than the more protracted traditional ratemaking option.[600]

The Court in *KN Energy* upheld the Commission's use of cost spreading in connection with the allocation of take-or-pay costs among a pipeline's open access customers.[601] The Court held that ''the ratemaking rationales of Order No. 500 can be reconciled with the NGA, given the unusual circumstances surrounding the take-or-pay problem, and the limited nature—both in time and scope—of the Commission's departure from the cost-causation principle.'' [602] The Court emphasized that ''[w]e hold only—and quite narrowly—that in the context of Order No. 500 the Commission has not betrayed its obligations to the NGA or precedent by employing these ratemaking principles in its attempt to bring closure to the take-or-pay drama.'' [603]

The unusual circumstances that justified the departure from cost causation principles in Order Nos. 500/528 are not present in the electric industry. In Order No. 888's discussion of the Commission's decision not to order any generic abrogation of existing requirements and transmission contracts between electric utilities and their customers, we have already pointed out:

> At the time the Commission addressed this situation in the natural gas industry, it was faced with shrinking natural gas markets, statutory escalations in natural gas prices under the Natural Gas Policy Act, and increased production of gas. In other words, there was a market failure in the industry. * * * In contrast, there is no such market failure in the electric industry.[604]

The electric utility costs potentially stranded by Order No. 888 are fixed costs arising from the utility's electric generation business, including, for example, depreciation expense associated with the utilities' own generation facilities and a return on the original cost of its investment in those facilities. They also include costs associated with mandatory QF purchase contracts. Unlike take-or-pay settlement costs, these costs are not an extraordinary expense that the Commission has never previously encountered. Rather, the stranded electric costs that are subject to the direct assignment provisions of Order No. 888 are ordinary costs that have always been, and are currently, included in the utility's rates for electric generation approved by the Commission. And there is no pre-existing industry-wide market failure. Thus, we are not confronted at the start of the electric open access program with a vast outstanding cost not currently reflected in the electric utilities' rates, as we were at the start of the natural gas open access program.

Therefore, unlike the situation with the natural gas industry, stranded electric utility costs can be allocated among customers based upon traditional cost causation principles without imposing inequitable and unreasonable burdens on particular customer classes. Direct assignment to departing requirements generation customers through the stranded cost recovery mechanism contained in the Rule is consistent with the traditional cost causation principle because it recognizes the link between the incurrence of stranded costs and the decision of a particular generation customer to use open access transmission on the utility's system to leave the utility's generation system and shop for power, and bases the utility's ability to recover stranded costs on its ability to demonstrate that it incurred costs with the reasonable expectation that the customer would remain on its generation system beyond the term of the contract. The stranded costs are measured as the difference between revenues the utility would have recovered from the customer and the market value of the utility's power.

In essence, therefore, all that the direct assignment provisions of Order No. 888 require is that certain customers (those whom a utility is able to demonstrate it reasonably expected to continue serving beyond the contract term) who convert to transmission-only service continue, for a period, to bear certain generation costs that they were previously bearing. This helps to minimize immediate cost shifts to the remaining generation customers, and is thus consistent with the Court's concerns in *AGD* about cost shifts due to open access transportation.[605] At the same time, it does not impose any crushing new burden on the converting generation customers, as would have happened if in the natural gas industry the Commission had allocated the take-or-pay settlement costs entirely to pipeline sales customers who converted to transportation-only service.

On the issue of utility absorption of stranded costs, as ELCON points out, the D.C. Circuit in *United Distribution Companies* remanded Order No. 636 to the Commission for further explanation as to why the Commission had exempted pipelines from sharing in Order No. 636 GSR costs in light of: (1) Its reliance on ''cost spreading'' and ''value of service'' principles in allocating GSR costs among the pipelines' customers, and (2) the absorption requirement in Order Nos. 500/528. As the Court explained:

> If the Commission intends to assign GSR costs according to these 'cost spreading' and 'value of service' principles, it must do so consistently or explain the rationale for proceeding in another manner. We approved the invocation of those principles in *KN Energy* because FERC had concluded that the take-or-pay crisis could be resolved only by spreading costs throughout the '*entire industry*' 968 F.2d at 1301 (emphasis added), and because we recognized that '*all segments of the industry*' * * * will benefit, *id*. (emphasis added), from restructuring.[606]

For the reasons discussed above and in Order No. 888, we have chosen to use traditional cost causation principles both in allocating stranded electric costs to certain electric utility customers and in finding that the utilities should be given an opportunity for full recovery of certain legitimate, prudent, and verifiable stranded costs. Thus, Order No. 888 does not present the issue of whether the Commission inconsistently applied ratemaking principles to the recovery of stranded costs that was of concern to the court in *United Distribution Companies* when it remanded the analogous portion of Order No. 636.

Moreover, based on the facts summarized above, the Commission concludes that the rationale we used to support the Order Nos. 500/528 absorption requirement is not valid for electric utility costs stranded by Order No. 888. Order No. 528–A, where the Commission gave its fullest justification for that absorption requirement, did not rely on either the ''cost spreading'' or ''value of service'' rationales to support the absorption requirement.[607] Order Nos. 500/528 consistently recognized that the Commission must ''provide a pipeline a reasonable opportunity to

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[600] 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.

[602] *KN Energy*, 968 F.2d at 1301.

[603] *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).

recover its prudently incurred costs.'' [608] However, Order No. 528–A reasoned that, because the take-or-pay problem was caused more by general market conditions than by any regulatory action of the Commission, it was appropriate to require the pipelines to share in the losses arising from those market conditions as a condition to using the alternative recovery mechanism.[609]

In these circumstances, the Commission concludes that it would not be reasonable to require electric utilities to bear costs that, unlike the Order Nos. 500/528 take-or-pay costs, arise as the direct result of Congress' and the Commission's change in the regulatory regime through FPA section 211 and Order No. 888. This is particularly the case since the electric utilities' potential stranded costs relate to large capital expenditures or long-term contractual commitments (some mandated by federal law) to buy power made many years ago in reliance on the preexisting regulatory regime.

Moreover, in a separate order, the Commission is responding to the *United Distribution Companies* remand by reaffirming the policy established in Order No. 636 that pipelines should be permitted full recovery of their prudently incurred GSR costs. In that order, the Commission finds that the rationale Order No. 528–A used to support the Order Nos. 500/528 absorption requirement is inapplicable to GSR costs. The remand order explains that, in the face of extraordinary market conditions, Order Nos. 500/528 adopted extraordinary measures. However, as we are finding here with respect to stranded electric utility costs, the remand order holds that the extraordinary market circumstances that gave rise to the requirement for pipeline absorption of gas supply costs in Order Nos. 500/528 were not present at the time of Order No. 636. Even before the Commission initiated open access transportation in Order No. 436, the market was preventing pipelines from recovering costs incurred under their take-or-pay contracts. The Order Nos. 500/528 absorption requirement reflected the preexisting effect of the market, which would have required absorption even without open access transportation under Order No. 436. The remand order finds that, contrary to the situation when Order No. 436 issued, at the time of Order No. 636, pipelines were generally able to take gas under their few remaining high-priced take-or-pay contracts from the late 1970s and early 1980s and were no longer accumulating significant additional take-or-pay obligations. This was because the pipelines were still performing a significant sales service and had reformed most of their uneconomic take-or-pay contracts.[610]

The remand order accordingly holds that the Commission's regulatory actions in Order No. 636 have caused the pipelines to incur the GSR costs. This is particularly the case because Order No. 636 required the pipelines to unbundle their natural gas and transportation sales and forbade the pipelines from making sales unless they were made by a separate sales or marketing entity. Order No. 888 also requires generation or commodity sales to be unbundled from sales of transmission. In these circumstances, traditional ratemaking principles require the Commission to allow the pipelines an opportunity to recover the full amount of the expenses caused by its actions. Thus, the Commission's approach to Order No. 636 GSR costs is similar to its approach in Order No. 888 to stranded electric generation costs.

Rehearing Requests Citing Other Inconsistencies Between Commission Treatments of the Gas and Electric Industries

VT DPS and Valero submit that Order No. 888 does not satisfactorily distinguish the Commission's rejection of gas pipelines' attempts to impose exit fees on departing customers. They argue that the Commission opposed the imposition of such exit fees in the gas context as anticompetitive because it would force customers desiring to switch suppliers when their contracts expired to pay the supply costs of both the new and former suppliers.

VT DPS and Valero take issue with the Commission's attempt to distinguish a recent *El Paso* case [611] as a ''post-restructuring'' case under Order No. 636. They contend that the Commission consistently applied the same policy (rejection of gas pipeline attempts to impose exit fees) before restructuring under Order No. 636. They further claim that the Commission cannot articulate a plausible basis for permitting utilities with notice provisions to file for exit fees, having denied El Paso's proposal outright without giving it an opportunity to rebut the presumption.

VT DPS and Valero also state that the ''stranded'' costs for which the Commission allowed recovery under Order No. 636 were costs that would be rendered unrecoverable because the costs would not be incurred to provide transportation service and because there would be no wholesale load from which to recover the costs. They indicate that the Commission has held that such gas costs are stranded only if rendered unrecoverable as a direct result of the restructuring required under Order No. 636. They submit that when a utility loses wholesale load or a municipality establishes a new distribution system and the utility cannot resell the capacity left unused, the utility's costs are not necessarily ''stranded''—*i.e.*, rendered unrecoverable—any more than if the utility's load declines because of conservation, an economic downturn or an increase in self-generation. They argue that the Commission should limit utility stranded cost claims solely to those cases where the utility can demonstrate that its costs have been rendered unrecoverable as a direct result of the Rule.

Commission Conclusion

We explained in Order No. 888 why we disagree with the argument that the Commission cannot impose an exit fee to recover stranded costs because the Commission did not allow gas pipelines to do so. We noted that the Rule establishes procedures for providing a potential departing generation customer advance notice (*before* it leaves its existing supplier) of the stranded cost charge (whether it is to be paid as an exit fee or a transmission surcharge) that will be applied if the customer decides to buy power elsewhere and the Commission decides the utility has satisfied the stranded cost recovery criteria of the Rule, *e.g.*, the reasonable expectation criterion. We indicated that in the natural gas context, in contrast, the Commission has prohibited

[608] 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.

[609] 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*).

pipelines from developing and charging an ''exit fee'' *after* a customer had implemented its gas purchase decision, noting that otherwise, the customer would not know in advance the full cost consequences of its nomination decision.[612]

We continue to believe that the Commission's decisions concerning natural gas pipeline exit fees, relied on by VT DPS and Valero, are not inconsistent with Order No. 888's limited approval of exit fees for the recovery of certain stranded electric utility costs. VT DPS and Valero point first to two cases decided by the Commission in 1988 and 1989 involving Gas Inventory Charges (GICs) proposed by Transwestern Pipeline Company (Transwestern)[613] and El Paso Natural Gas Company (El Paso)[614] pursuant to our Order No. 500 policy statement. However, those cases are not relevant here, essentially because the exit fees at issue in those cases were not designed to recover costs arising from the transition to open access transportation, unlike the stranded electric utility costs at issue here.

In the *Transwestern* case cited by VT DPS and Valero, Transwestern included in its proposal to implement a GIC a request for permission to assess an exit fee. The exit fee would have been charged to its largest local distribution company customer if that customer initially chose to nominate purchases under the GIC but then subsequently reduced its nominations. The Commission found the proposed exit fee inconsistent with both (1) its policy that GIC customers know in advance the full cost consequences of their nomination decisions and (2) its objective that prices under the GIC be constrained by market forces.

However, this holding was not applicable to Transwestern's recovery of costs incurred as part of its transition to open access transportation, since the Commission did not intend the GIC as a vehicle for recovery of such transition costs. The GIC was intended solely as a forward-looking charge that would recover costs the pipeline would incur in the future under its reformed, market responsive gas supply contracts.[615] The Commission's intent was that, before implementing GICs, pipelines would negotiate settlements of their existing uneconomic take-or-pay contracts and file to recover the resulting settlement costs under the Order No. 500 equitable sharing mechanism.[616] Indeed, in the *Transwestern* order cited by VT DPS and Valero, the Commission suggested that Transwestern postpone implementation of its GIC until it had renegotiated its supply contracts and filed to recover the resulting costs under the Order No. 500 equitable sharing mechanism.[617]

That mechanism included a fixed take-or-pay charge analogous to the direct assignment provisions of Order No. 888. The Commission permitted pipelines to allocate to sales customers who converted from sales to transportation the same fixed take-or-pay charge that those customers would have been allocated had they not converted.[618] Moreover, in a later order involving Transwestern's recovery of take-or-pay settlement costs under its Order No. 500 equitable sharing mechanism, the Commission expressly held:

> In appropriate circumstances, the Commission may approve exit fees for departing customers, either through a condition on the abandonment of the purchase obligation of customers subject to the Commission's jurisdiction or through tariff language giving appropriate notice of such a fee before the departure.[619]]

As discussed in the preceding section of this order, the direct assignment provisions of Order No. 888, in essence, require that certain electric generation customers who convert to transmission-only service continue, for a period, to bear certain generation costs that they were previously bearing. That requirement is similar to the Commission's requirement, in connection with its Order No. 500 program, that pipeline sales customers who convert to transportation-only service continue to pay the same Order No. 500 fixed take-or-pay charge as they would have paid had they not converted.

VT DPS and Valero also claim that permitting electric utilities to recover stranded generation costs through exit fees to customers converting to transmission-only service is inconsistent with our 1995 order in *El Paso*,[620] rejecting that pipeline's exit fee proposal. We see no inconsistency. El Paso proposed, several years after its restructuring pursuant to Order No. 636, to impose an exit fee on its firm *transportation* customers who terminated or reduced their firm transportation service. The fee was designed to require the departing firm transportation customer to continue to pay a portion of El Paso's fixed transmission costs for a period of time after the customer's departure. The fee bore no relationship to El Paso's pre-restructuring merchant function, since it was designed to recover El Paso's costs of performing open access transportation service after its restructuring.

In both Order No. 888 and this order, we are acting consistently with *El Paso*. Similar to our refusal in *El Paso* to permit a pipeline to impose an exit fee on customers departing its transportation system altogether (whether for all or a portion of their firm service), so also here we are refusing to permit electric utilities to recover stranded costs from customers who depart their transmission systems altogether. We believe that, in that situation, there is no direct nexus between the customer's departure (and the stranding of costs) and Commission-required transmission access, since the customer is not using its former supplier's open access tariff to reach an alternative power supplier.

Order No. 888 thus permits an exit fee only to electric generation customers who, although they stop purchasing power from the utility, become transmission-only customers of the former supplying utility.[621] By contrast,

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

[613] Transwestern Pipeline Company, 44 FERC ¶ 61,164 at 61,536 (1988) (*Transwestern*).

[614] 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).

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

[617] *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

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El Paso proposed an exit fee to transmission customers terminating their transmission service. In short, the exit fee we have found acceptable in Order No. 888 is related to the electric utility's pre-restructuring generation service, unlike El Paso's rejected exit fee, which bore no relationship to El Paso's pre-restructuring merchant service.[622]

Finally, VT DPS's and Valero's comments concerning the Commission's treatment of Order No. 636 ''stranded costs'' attempt to make distinctions that do not make a difference for purposes of the Commission's treatment of Order No. 888 stranded costs. We have explained above that the electric industry's transition to an open transmission access, competitive industry is different in a number of respects from the natural gas industry's transition to open access transportation service by interstate natural gas pipelines. We also have explained why a different approach to recovery of legitimate, prudent and verifiable stranded costs in the electric industry is justified. On this basis, the Commission's definition and treatment of ''stranded'' costs under Order No. 636 need not dictate our definition and treatment of stranded costs under Order No. 888. In any event, in response to VT DPS's and Valero's request that the Commission limit utility stranded cost claims solely to those cases where the utility can demonstrate that its costs have been rendered unrecoverable as a direct result of the Rule,[623] we note that Order No. 888 does require a causal nexus between the availability and use of Commission-required transmission access and the stranding of costs.

Rehearing Requests Opposing Recovery of Stranded Costs in Transmission Rates

VT DPS and Valero submit that although the Commission has not proposed to depart from cost-based ratemaking methodologies in establishing transmission rates, Order No. 888 contravenes cost causation principles by recovering generating costs in transmission rates.[624] They argue that although the court in *KN Energy* held that the Commission might depart from strict cost-causation principles to permit pipelines to recover gas supply costs from transportation customers in extraordinary circumstances, the ''extraordinary circumstances'' were that the pipelines had no remaining sales customers and thus were left with no vehicle for recovering gas supply costs. On this basis, the court approved a mechanism under which gas supply costs were spread over virtually all transmission users. They describe as incongruous the Commission's claim in Order No. 888 that permitting direct assignment of stranded power costs in a transmission rate is a cost-based approach.

VT DPS and Valero further argue that even if the Commission were inclined to justify stranded cost recovery from departing customers on non-cost grounds, the Commission cannot show that the circumstances justifying similar cost recovery from gas pipeline transportation customers exist at the wholesale level in the electric industry because: (1) unlike its approach to gas pipelines, the Commission has not proposed to allow existing wholesale electric customers to get out of their contracts early; (2) there is no industry-wide problem; wholesale sales account for only a small fraction of the total business of regulated electric utilities, while gas pipelines had virtually all wholesale sales; and (3) direct assignment of generating costs only to departing customers is the antithesis of the cost-spreading rationale that provided the justification for the limited departure from cost-causation principles permitted in *KN Energy*. They contend that, in any event, the Commission cannot spread costs broadly even if they are recovered from all transmission customers because the largest users are retail customers that would be exempt from wholesale stranded cost surcharges.

A number of other entities also oppose the recovery of stranded generation costs in transmission rates.[625] Some of them contend that section 212(a) of the FPA limits the transmitting utility to the recovery of transmission-related costs.[626] PA Munis contends that the plain language of section 212, as amended by EPAct, limits the rates that can be charged under a section 211 order to those '' 'which permit the recovery by such utility of all the costs incurred in connection with the transmission services and necessary associated services * * *' ''[627] PA Munis contends that Congress would not have limited recovery to the costs incurred in connection with the transmission services and necessary associated services if it had intended to allow the transmission rates to include part of a utility's costs for unused generation facilities completely unrelated to the cost of the transmission facilities.[628] PA Munis asserts that the legislative history of EPAct supports its position that there is no authorization for the Commission to include unused generation costs as part of the transmission costs that are allocable to transmission under section 212.[629]

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.

622 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.

626 *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).

628 *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).

AR Com and MO/KS Coms argue that the FPA does not allow the Commission to include costs in a transmission rate that are not caused by the provision of transmission service.[630] MO/KS Coms contend that retail stranded costs are largely generation costs that were not caused by any request to use transmission service or by any actual transmission usage, and are not an opportunity cost of providing transmission service. Citing the language in section 212 of the FPA allowing the transmitting utility to recover ''all costs incurred in connection with the transmission services and necessary associated services,'' AR Com contends that nowhere does the Energy Policy Act or any other relevant statute authorize the collection of retail, non-transmission costs through transmission rates.

Commission Conclusion

We disagree with VT DPS's and Valero's argument that Order No. 888 contravenes cost causation principles by recovering generating costs in transmission rates. As the court in *United Distribution Companies* stated: '' 'Cost causation' correlates costs with those customers for whom a service is rendered or a cost is incurred.'' [631] Whether stranded costs are recovered through a surcharge on the transmission rates of a departing generation customer, or through an exit fee, the point is that under Order No. 888 they are recovered from the customer that caused them to be incurred. The only distinction is the mechanism by which they are recovered from that customer.

The Commission is not aware of any prohibition on permitting recovery through a transmission rate of what has traditionally been recovered through the generation component of a rate, so long as the utility does not double recover and the customer does not pay more than the costs that it caused to be incurred.[632] Indeed, the Commission has been upheld in permitting opportunity costs (foregone economic savings) to be charged as a transmission rate when they are higher than a traditional embedded cost transmission rate.[633] There is no significant difference between an ''opportunity cost'' component of a transmission rate and a stranded cost charge imposed through transmission rates. Both concern the recovery of generation costs. To be sure, in the former case these generation costs are incurred by reason of using high cost generation instead of substituting lower cost generation, and in the latter case the costs are ''incurred'' by reason of the loss of a customer.[634] But, for purposes of cost recovery, these are distinctions without a difference. In both situations, the transmission rate is used to recover something other than the capital, operating, and maintenance costs of facilities used to provide the transmission service at issue. If the Commission were without authority to provide for cost recovery of these other types of costs in transmission rates, the court would not have affirmed the volumetric surcharge on transportation in *KN Energy,* nor would it have affirmed the opportunity cost charge in *Penelec.*

As we note above, we are *not* proposing a departure from strict cost-causation principles such as that allowed in *KN Energy,* where the pipeline was allowed to recover 50 percent of its take-or-pay settlement costs through a volumetric surcharge on all transportation customers, including those that had never purchased gas from the pipeline.[635] Because we disagree with VT DPS's and Valero's position that recovery of stranded costs through a surcharge on transmission constitutes recovery on non-cost grounds,[636] we will reject their requests for rehearing on this issue.[637]

We also reject the argument that section 212 of the FPA prohibits the recovery of stranded generation costs in transmission rates. There is nothing on the face of the statute or in its legislative history to support this position. In fact, section 212(a) permits recovery of ''legitimate, verifiable and economic costs'' of providing transmission service. Stranded costs clearly are an economic cost of providing transmission when the stranding results from the ordered transmission service. By definition, the costs for which this Rule provides an opportunity for recovery would not have been stranded *but for* Commission-mandated transmission access. Stranded costs under this Rule are the costs that a utility incurred to provide service to a customer based on a reasonable expectation that the utility would continue to serve the customer beyond the term of their contract, and that become stranded when the customer uses Commission-mandated

[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.

[633] *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.

[634] 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.

[636] 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.

[637] 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.

transmission access to reach a new generation supplier. In this respect, stranded costs, like opportunity costs,[638] are not costs associated with the actual facilities used to provide transmission service. Rather, they are an ''economic cost'' of providing the transmission service at issue.

4. Recovery of Stranded Costs Associated With New Wholesale Requirements Contracts

In Order No. 888, we concluded that future wholesale requirements contracts should explicitly address the mutual obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. This means that utilities must address potential stranded cost issues when negotiating new contracts or be held strictly accountable for the failure to do so.

We stated that we will allow recovery of wholesale stranded costs associated with any new requirements contract (executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994) only if explicit stranded cost provisions are contained in the contract. We defined ''explicit stranded cost provision'' (for contracts executed after July 11, 1994) as a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate. However, for purposes of requirements contracts executed after July 11, 1994 but before May 10, 1996 (the date on which Order No. 888 was published in the Federal Register), we clarified that a provision that specifically reserved the right to seek stranded cost recovery consistent with what the Commission permits in the Final Rule (without identifying the specific amount of stranded cost liability of the customer(s) and calculation method) nevertheless will be deemed an ''explicit stranded cost provision.'' On the other hand, a provision in a requirements contract executed after July 11, 1994 but before May 10, 1996 that merely postpones the issue of stranded cost recovery without specifically providing for such recovery will *not* be considered an ''explicit stranded cost provision.'' We said that, after May 10, 1996, a provision must identify the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate in order to constitute an ''explicit stranded cost provision.'' [639]

We also concluded that a requirements contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a ''new'' requirements contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.

We decided not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve the power needs of their existing requirements customers beyond the end of the contract term. The only exception to this would be if the customer decides to remain a requirements customer for the period for which the Commission finds that the supplying utility reasonably expected to continue serving the customer. In such a case, the supplying utility will be obligated to offer continuing service to the requirements customer for the period the utility reasonably expected to continue serving the customer.

We also decided to no longer require prior notice of termination under section 35.15 for any power sales contract executed on or after July 9, 1996 (the effective date of the Final Rule pro forma tariff) that is to *terminate by its own terms* (such as on the contract's expiration date), but to require written notification of the termination of such contract within 30 days after termination takes place. We said that we will continue to require prior notice of the proposed termination of any power sales contract executed before July 9, 1996 (even if the contract is to terminate by its own terms) as well as any unexecuted power sales contract that was filed before that date.

Further, we decided to retain the section 35.15 filing requirement for all transmission contracts because the Commission must be assured that transmission owners are not exerting market power in negotiating or terminating transmission contracts. This filing requirement will provide the customer an opportunity to notify the Commission if the termination terms are disputed or if the customer was not given adequate opportunity to exercise its limited right of first refusal under the Final Rule (*see* Section IV.A.5).[640]

Requests for Rehearing

Utilities For Improved Transition asks the Commission either to clarify that it will enforce stranded cost provisions as agreed to by the parties and accepted for filing by the Commission (presumably even if they do not meet the definition of ''explicit stranded cost provision'' contained in the Preamble [641]), or to modify the definition contained in the Preamble (and add the term to the list of definitions in section 35.26(b)) to give contracting parties the option of specifying either a specific amount of stranded cost liability *or* a formula for calculating the stranded cost charge or rate. Utilities For Improved Transition contends that, particularly in the case of long-term contracts, the parties may not be able to quantify what the stranded cost liability will be at the time they enter into a contract.

Several entities assert that if the Commission is to permit recovery for stranded costs, it should include a symmetrical mechanism to permit customers with below-market rates or net undervalued assets a means to continue to receive power at below-market rates if the customer had a reasonable expectation of continued service.[642] OH Consumers' Counsel objects that the only exception in Order No. 888 to the Commission's decision not to impose a regulatory obligation on a utility to continue to serve existing requirements customers beyond the end of the contract ''would be if the customer decides to remain a requirements customer for the period for which the Commission finds that the *supplying utility reasonably expected* to continue serving the customer.'' [643] According to OH Consumers' Counsel, this language nullifies the *customer's* reasonable expectation of continuation of service under its existing contractual arrangement.

TDU Systems similarly says that the Commission has not explained why the suppliers' expectations are to be honored, but the customers' expectations are not. TDU Systems objects that the Commission failed to explain why it rejected allowing requirements customers to demonstrate a reasonable expectation that they would continue to be able to obtain supplies of power at rates based on embedded cost after the expiration of

[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.

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

their supply contracts. TDU Systems submits that the case for providing extra-contractual relief to wholesale purchasers is more compelling than the case for providing extra-contractual relief to wholesale suppliers. It argues that it is likely that some cooperatives and municipal utilities would not survive the drastic impact to their businesses that the elimination of cost-based rates could bring.

OH Consumers' Counsel submits that the filing of a section 206 complaint by customers of utilities with rates below market does not provide adequate protection or symmetry for the customers. It contends that a section 206 case is an inadequate remedy because: (1) the utility holds all of the necessary information for analyzing such a case, but the procedure shifts the burden of proof from the utility to the customer; and (2) it provides only delayed relief for parties who could be irreparably harmed by the imposition of the market-based rates.

TDU Systems argues that eliminating the prior notice of termination requirement in section 35.15 for post-July 9, 1996 wholesale requirements contracts will result in discrimination and monopolization. It contends that the Commission closes its eyes to the fact that termination of a requirements contract can affect 100 percent of a customer's power supply, while it is likely to affect less than 10 percent of a large public utility's load. It submits that eliminating the prior notice of termination requirement is tantamount to finding that termination of all such contracts by their terms will be just and reasonable, but that no such finding can presently be supported. TDU Systems maintains that there remains significant market power in the markets in which transmission dependent utilities, especially small transmission dependent utilities, operate. It recommends that the Commission use section 35.15 to require that wholesale contracts not be terminated unless such termination is just and reasonable.

PA Munis objects that the Commission did not specifically address in Order No. 888 its proposal that contracts approved after July 11, 1994 (but executed before that date) be treated as new contracts. It submits that under the Commission's reasoning in setting the July 11, 1994 cut-off date, utilities that executed requirements contracts after that date had no reasonable expectation that they would be permitted to recover costs by seeking to amend the contract. It argues that the same reasoning applies where the contract was executed but not approved or accepted by the Commission by the July 11, 1994 notice date.

Commission Conclusion

We will clarify the definition of "explicit stranded cost provision" for requirements contracts executed after July 11, 1994. As long as the contracting parties are in agreement, a provision in a post-July 11, 1994 requirements contract will be considered an "explicit stranded cost provision" if it identifies *either* the specific amount of stranded cost liability of the customer *or* a specific method for calculating the stranded cost charge or rate.

We will reject the arguments of TDU Systems and OH Consumers' Counsel that "symmetry" requires that the Commission provide a generic mechanism in this Rule to allow existing requirements customers with below-market rates a means to continue to receive power beyond the contract term at the pre-existing contract rate if the customer had a reasonable expectation of continued service. Unlike the generic findings we have made with respect to extra-contractual recovery of stranded costs associated with requirements contracts executed on or before July 11, 1994, we do not have a sufficient basis on which to make generic findings that customers under such contracts may be entitled to extend a contract *at the existing rate*. Utilities' expectations may have resulted in millions of dollars of investments on behalf of certain customers and the possibility of shifting the costs of those investments to other customers that did not cause the costs to be incurred. In the case of customers' expectations, however, even if customers generally expected to stay on a supplier's system beyond the contract term, it is not likely that most customers could have expected to continue service *at the existing rate* unless specified in the contract. Moreover, the consequences of customers' expectations as a general matter would not have the potential to shift significant costs to other customers.

Nevertheless, our conclusion that we cannot make generic findings or provide a generic formula for addressing this issue does not mean that a customer under a contract may not exercise its procedural rights under section 206 to show that the contract should be extended at the existing contract rate,[644] or to make such a showing in the context of a utility's proposed termination of a contract pursuant to the section 35.15 notice of termination (approval) requirement, which we have retained for power supply contracts executed prior to July 9, 1996 (the effective date of the Rule).

We believe that while the relationship between utilities and their wholesale requirements customers may have given rise to an inference or expectation on the part of the wholesale requirements customer that the contract would continue beyond the stated term, it is not clear to what extent a customer could demonstrate a reasonable expectation that such continued service would be *at the existing contract rate* (which may be below the market price). This is particularly the case for contracts in which the utility has not waived its unilateral right to make section 205 filings to change the rates. Even in contracts where rates were fixed for the contract term, however, if the utility were to agree to extend such a contract for a new term, the rates under that contract would not necessarily have remained the same. On this basis, a customer may be able to demonstrate that it had a reasonable expectation of continued service beyond the contract term, but not necessarily at the same rate level. It is for this reason that we believe this issue must be addressed on a case-by-case basis and that this Rule is not the proper mechanism for granting the relief sought by TDU Systems and OH Consumers Counsel.

Nevertheless, we do not intend to prejudge whether a requirements customer could ever make a showing that it reasonably expected service beyond the contract term at the existing contract price. Nor do we intend to preclude a customer from attempting to make such a showing in appropriate circumstances.

We also believe that we adequately addressed in Order No. 888 TDU Systems' argument that elimination of the prior notice of termination requirement in section 35.15 for post-July 9, 1996, wholesale requirements contracts will result in discrimination and monopolization. As we stated in Order No. 888, we believe that the concerns of TDU Systems can be fully addressed without retaining the section

[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.

35.15 prior notice of termination requirement for post-July 9, 1996 contracts. While we have agreed to provide for extra-contractual stranded cost recovery as a *transition* matter, it is our objective that, prospectively, parties should address their mutual expectations clearly through contract terms that explicitly address the mutual obligations of the seller and buyer at contract expiration. This would include the seller's obligation to continue to serve the buyer after contract expiration, if any. If the customer believes that termination of its contract at the end of the term would not be just and reasonable (or, in the case of a *Mobile-Sierra* contract, would not be in the public interest), it can file a complaint with the Commission under section 206 of the FPA.

We will reject PA Munis' request that contracts approved after July 11, 1994 (but executed before that date) be treated as ''new'' contracts for purposes of stranded cost recovery because modifying the notice date at this point in the proceeding would work an inequitable result. Beginning with the initial stranded cost NOPR, the Commission put entities on notice that contracts ''executed'' on or before July 11, 1994 would constitute ''existing'' contracts. Although a utility arguably could have amended such an existing contract to include an explicit stranded cost provision prior to its (post-July 11, 1994) approval by the Commission, the NOPR did not require the utility to do so. As a result, it would be unfair for the Commission to change the cut-off terms now.

5. Recovery of Stranded Costs Associated With Existing Wholesale Requirements Contracts

In Order No. 888,[645] the Commission concluded that it would permit utilities the opportunity to seek recovery of legitimate, prudent and verifiable stranded costs for ''existing'' wholesale requirements contracts (executed on or before July 11, 1994) that do not already contain exit fees or other explicit stranded cost provisions.[646] We explained why we believe that July 11, 1994—the date on which the initial Stranded Cost NOPR was published and, thus, on which the industry was put on notice of the proposal to disallow prospectively extra-contractual recovery of stranded costs—is the appropriate date for distinguishing ''existing'' requirements contracts from ''new'' requirements contracts.

We noted our desire that utilities attempt to renegotiate with their customers existing requirements contracts that do not contain exit fees or other explicit stranded cost provisions. If a contract is not renegotiated to add such a provision, we explained that, before the expiration of the contract: (1) A public utility or its customer may file a proposed stranded cost amendment to the contract under sections 205 or 206; or (2) a public utility in a section 205 proceeding, or a transmitting utility in a section 211 proceeding, may file a proposal to recover stranded costs associated with any such existing contract through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier.

We also concluded that, even if an existing requirements contract contains an explicit *Mobile-Sierra*[647] provision, it is in the public interest to permit the public utility to seek a unilateral amendment to add stranded cost provisions if the contract does not already contain exit fees or other explicit stranded cost provisions.[648] We explained why our determination that it is in the public interest to give public utilities a limited opportunity to propose contract changes unilaterally to address stranded costs if their contracts do not already explicitly do so satisfies the public interest standard of the *Mobile-Sierra* doctrine. We also indicated that customers with *Mobile-Sierra* contracts that do not explicitly address stranded costs may file complaints under section 206 of the FPA to propose to address stranded costs in existing requirements contracts.

We concluded that a public utility or its customer should be allowed to file a proposed stranded cost amendment, or a public utility or transmitting utility should be allowed to file a proposal to recover stranded costs through a departing generation customer's transmission rates, at any time prior to the expiration of the contract.

Rehearing Requests—July 11, 1994 Cut-Off Date

Utilities For Improved Transition, repeating an argument raised in previous comments in this proceeding, objects to the Commission's July 11, 1994 cut-off date for distinguishing between ''existing'' and ''new'' requirements contracts. It argues that stranded cost recovery should be assured for all contracts executed before the effective date of the Rule (*i.e.*, July 9, 1996), not just those executed before July 11, 1994. It asserts that parties to contracts executed after July 11, 1994 but before July 9, 1996 should have the same opportunity as parties to pre-July 11, 1994 contracts to offer evidence as to their reasonable expectations. Utilities For Improved Transition asserts that agencies may not promulgate retroactive rules without express statutory authority,[649] and that the FPA does not give the Commission such statutory authority.

Puget raises a somewhat different point. It notes that the definition of a ''new'' requirements contract as ''any wholesale requirements contract * * * *extended or renegotiated to be effective after July 11, 1994*'' (emphasis added) was not proposed until March 29, 1995 (in the supplemental stranded cost NOPR). Puget states that the initial stranded cost NOPR proposed to give a utility three years from the date of Federal Register publication of the final stranded cost rule to negotiate or to file for stranded cost recovery. According to Puget, the March 1995 supplemental stranded cost NOPR proposed a retroactive change by defining a contract executed prior to July 11, 1994 but extended or renegotiated to be effective after that date as a ''new'' contract and by removing the three-year window for negotiating stranded cost recovery. By this change, Puget argues that the extension of a contract between the date of Federal Register publication of the initial NOPR (July 11, 1994) and the issuance of the supplemental NOPR (March 29, 1995) may have converted it into a ''new'' rather than an ''existing''

[645] FERC Stats. & Regs. at 31,809–814; *mimeo* at 510–24.

[646] 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).

[648] 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).

contract for stranded cost recovery purposes. Puget asks the Commission to revise the definition of ''existing wholesale requirements contract'' in Order No. 888 and 18 CFR 35.26 to include contracts executed on or before July 11, 1994 that were extended prior to the issuance of the supplemental stranded cost NOPR (March 29, 1995) and for which stranded cost provisions were filed with the Commission prior to issuance of Order No. 888. Puget submits that failure to do so would be arbitrary and capricious and would deprive utilities with such contracts of adequate notice of a proposed rule.[650]

Commission Conclusion

We will reject Utilities For Improved Transition's rehearing request because we believe that we adequately explained in Order No. 888 why adoption of the July 11, 1994 cut-off date is appropriate and does not constitute retroactive rulemaking. We said in Order No. 888 that because all parties were put on notice in the initial stranded cost NOPR that July 11, 1994 would be the operable date for the ''existing''/''new'' contract distinction, utilities that executed requirements contracts after that date could have had no reasonable expectation that they would be permitted to recover any costs extra-contractually. Moreover, we explained that because the costs at issue are extra-contractual costs, the Commission's notice to all parties that contracts executed after July 11, 1994 (the date that the initial NOPR was published in the Federal Register) will be enforced by their terms as far as stranded cost recovery is concerned does not constitute ''retroactive rulemaking.'' The Commission has merely put all parties on notice that the opportunity for extra-contractual stranded cost recovery would not be available for any requirements contracts executed after July 11, 1994.

The July 11, 1994 date is appropriate because it is the date on which all interested parties were given notice in the Federal Register that the recoverability of stranded costs for contracts executed on or before that date that did not provide for such recovery was at issue. The parties to requirements contracts executed after July 11, 1994 have been free to provide for stranded cost recovery in the contract, or not. The point is that, for requirements contracts executed after the cut-off date, stranded cost recovery will be governed solely by the terms of the contract.

We believe that Puget has raised a valid point concerning the potential impact of the Commission's decision in the March 29, 1995 supplemental stranded cost NOPR to treat extensions or renegotiations of existing contracts as ''new'' contracts for stranded cost purposes on parties that extended or renegotiated an existing contract prior to March 29, 1995. However, we expect that the situation described by Puget may be an isolated instance. On this basis, we do not believe it necessary to modify the definition of ''existing wholesale requirements contracts'' in Order No. 888 and 18 CFR 35.26 as requested by Puget. Nevertheless, we clarify that we will consider on a case-by-case basis whether to waive the provisions of 18 CFR 35.26 and to treat a contract extended or renegotiated (without adding a stranded cost provision) to be effective after July 11, 1994 but before March 29, 1995 as an existing contract for stranded cost purposes.[651]

Rehearing Requests—Mobile-Sierra

Several entities challenge the Commission's generic *Mobile-Sierra* public interest finding. According to APPA, the Commission cannot make the public interest determination in a generic rulemaking, whether for stranded cost or non-stranded cost modifications.

A number of entities object that the Commission does not identify any utilities whose existence is jeopardized without full wholesale stranded cost recovery.[652] PA Munis and APPA assert that vague allegations of harm if utilities do not recover stranded costs do not satisfy the public interest standard which they view to be ''practically insurmountable.''[653] American Forest & Paper contends that there is not one fact to support the Commission's assumption about threats to the financial stability of the electric utility industry. ELCON submits that significant retail stranded cost exposure does not justify the rule on wholesale stranded cost recovery.

VT DPS and Valero submit that the Commission has not explained how allowing utilities to abrogate their contracts to extract exit fees from former customers vindicates any public interest. They argue that even assuming that wholesale customers depart en mass, the customers can only do so as their contracts expire; thus, the exodus, if it occurs, will be a trickle, not a flood. VT DPS and Valero maintain that even if some utilities were put at risk, it would not justify a generic rule. They contend that based on *AGD* v. *FERC*,[654] a generic solution is not proper for a problem existing only in ''isolated pockets.''

PA Munis submits that, even assuming that the financial integrity of some utilities may be threatened, the missing link in the Commission's logic for a generic rule is 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. PA Munis asserts that, at a minimum, each utility having *Mobile-Sierra* contracts should be required to show on an individual basis that the public interest standard has been satisfied.

American Forest & Paper argues that Order No. 888 is not made even-handed by allowing requirements customers to also challenge fixed-rate, fixed-term contracts. It submits that letting a customer file to amend a contract only as long as that amendment also addresses stranded costs is a ''heads you win, tails I lose'' proposition for the customer.

APPA and TDU Systems request clarification of the scope of the Commission's decision to allow a utility ''to seek modification of contracts that may be beneficial to the customer'' if the customer is permitted to argue for modification of existing contracts that are less-favorable to it than other generation alternatives. APPA expresses concern that this language could be interpreted to mean that once a

[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.

[653] *See also* ELCON.

[654] 824 F.2d at 1019.

customer seeks modification of stranded cost provisions in an existing contract, the utility may be able to challenge its entire contract with the customer. If this means the utility can modify contract provisions unrelated to stranded costs, APPA submits that the Commission has failed to address the *Mobile-Sierra* public interest issues associated with modifying non-stranded cost provisions in an existing contract. If not, APPA contends that the Commission should clarify the language. APPA objects that the Commission has not placed any limits on the types of modifications that a selling utility can make, nor specified the types of changes that it thinks a utility will likely make. It states that the Commission needs to explain why joint modification by both the seller and the purchaser can meet the public interest standard. According to APPA, the Commission has not explained the need for symmetrical treatment of contracts negotiated at a time when the Commission has found that the supplying public utilities were exercising their monopoly over transmission facilities in an unduly discriminatory manner.

APPA also contends that the Commission's reliance on *Northeast Utilities* [655] is misplaced because that case involved the Commission's review of a newly-filed contract, as opposed to subsequent review of a contract previously accepted and approved by the Commission. APPA further asserts that *Northeast Utilities* involved an affiliate transaction, whereas this rulemaking is targeted at arm's-length agreements between unrelated selling and purchasing utilities. According to APPA, this rulemaking does not present any of the concerns at issue in an affiliate transaction, and the Commission should have applied the ''practically insurmountable'' public interest standard doctrine from *Papago,* the classic ''low-rate'' case.

Commission Conclusion

We disagree with those entities that argue that the Commission cannot make the public interest determination in a generic rulemaking. It is well established that it is within the Commission's discretion to decide whether we act through rule or through case-by-case adjudications.[656] As we explained in Order No. 888, we believe it is appropriate that our public interest finding be made on a generic basis given the fact that, by this Rule, we are requiring full open access that could significantly affect historical relationships among traditional utilities and their customers and the ability of utilities to recover prudently incurred costs.

At the same time, however, we are not eliminating the need for case-by-case demonstrations that stranded cost recovery should be allowed. Our public interest finding is that utilities be permitted to *seek* extra-contractual recovery of stranded costs in certain defined circumstances and that they be allowed to recover stranded costs *only* if they make a case-specific demonstration.

Our holding applies only to wholesale requirements contracts (with *Mobile-Sierra* clauses) executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision. We will not permit modification of any contract that addresses the stranded cost issue explicitly, unless the contract specifically permits such modifications. Instead, we are examining requirements contracts that do not clearly address the issue in the context of the traditional regulatory regime under which they were signed—a regulatory environment in which it was assumed as a matter of course that the great majority of requirements customers would stay with their original suppliers and that these suppliers had a concomitant obligation to plan to supply these customers' continuing needs.

Further, utilities with *Mobile-Sierra* contracts that seek recovery of stranded costs will have the burden, on a case-by-case basis, of showing they had a reasonable expectation of continuing to serve the departing generation customer. Although we have decided on a generic basis that it is in the public interest to permit public utilities with *Mobile-Sierra* contracts to make unilateral filings, we are not automatically approving any amendment that a particular utility might file. If a public utility unilaterally files a proposed stranded cost amendment under either section 205 or 206 of the FPA, this does not necessarily mean that the Commission will find it appropriate to allow such amendment. In addition, customers with *Mobile-Sierra* contracts that do not explicitly address stranded costs may also file complaints under section 206 of the FPA to propose to address stranded costs in existing requirements contracts. The Commission will analyze any proposed stranded cost amendment to a *Mobile-Sierra* contract, whether proposed by the utility or by its customer, based on the particular circumstances surrounding that contract. Thus, the case-by-case findings that some commenters seek will, in effect, be made when the Commission determines whether to approve a proposed stranded cost amendment to a particular contract.[657]

Although several entities have raised various challenges to the sufficiency of the Commission's public interest finding, we believe that we have satisfied the public interest standard by showing how third parties may ultimately bear the burden if public utilities with *Mobile-Sierra* contracts are not given any opportunity to propose contract changes to address stranded costs.[658] As we explained in Order No. 888, if the Commission fails to give a public utility this opportunity, and the utility's financial ability to continue the provision of safe and reliable service is impaired, third parties (customers relying on the public utility for their electric service) will be placed at risk. Similarly, if the Commission fails to give a public utility the opportunity to directly assign costs to the customers on whose behalf they were incurred, and some of the utility's customers leave the utility's generation system for that of another supplier without paying such costs, third parties (the utility's remaining customers) may be harmed by having to bear costs that were not incurred to serve them and that are stranded by the other customers' departures via open access transmission. We believe that protective action in the public interest is particularly necessary where, as here, a utility's rates could become insufficient because of fundamental changes in the industry that largely result from legislative or regulatory changes that could not be anticipated.

In response to those entities that contend that speculation of financial jeopardy or generalized statements of what may occur without reference to particular public utilities is not sufficient to satisfy the public interest standard, we disagree. The Commission need not make findings about particular utilities because the Rule does not

[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.

award stranded costs—it simply sets out generic criteria for determining recovery in a particular case. If a utility does not meet the criteria, there will be no stranded cost recovery. The public interest determination rests on the obvious conclusion that the failure of a utility to recover costs prudently incurred and financed based on investor expectation of traditional cost recovery clearly adds regulatory risk that investors reasonably did not expect.

VT DPS's and Valero's reliance on *AGD* as support for the proposition that, even if some utilities were put at risk, a generic solution is not proper for a problem existing only in ''isolated pockets'' is misplaced. The *AGD* court found that the Commission had not adequately justified its decision to give *all* bundled firm sales customers of a pipeline that decided to offer service under Order No. 436 the option to reduce their contract demand by 100 percent. In noting the lack of support for ''an industry-wide solution for a problem that exists only in isolated pockets,'' the court expressed concern that the remedy adopted by the Commission (''such drastic action as 100% CD reduction'' [659]) was too broad.

In Order No. 888, in contrast, the Commission has determined that it is in the public interest to give a *limited* class of utilities—those that are parties to wholesale requirements contracts that were executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision and that contain *Mobile-Sierra* clauses—an opportunity to seek to add a stranded cost provision to the contract. Thus, the narrow scope of the Commission's *Mobile-Sierra* public interest finding is a far cry from the broad remedy (100 percent CD reduction) that the court remanded in *AGD.* Indeed, it more closely resembles the type of limited generic action that the *AGD* court suggested would be proper when it stated: ''This is not to say, of course, that the Commission could not use generic rules to identify a limited class of LDCs to be entitled to reduce CD when special conditions are present.''[660]

We explained in Order No. 888 that we were making two complementary public interest findings. First, as described above, is our decision that it is in the public interest to permit public utilities to seek stranded cost amendments to existing requirements contracts with *Mobile-Sierra* clauses. Second, we found that a ''party'' to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract, but still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified. We clarify that, in making this second finding, our reference to a ''party'' to a requirements contract containing a *Mobile-Sierra* clause was directed at modification of contract provisions by customers.[661] Additionally, this second finding applies to any contract revisions sought, whether or not they relate to stranded costs.[662]

We also concluded that ''if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.'' [663] We clarify in response to APPA and TDU Systems that this statement was not intended to imply that the Commission had made *Mobile-Sierra* findings that would permit utilities with *Mobile-Sierra* contracts to seek non-stranded cost amendments to contracts that may be favorable to a customer, based on a showing that the contracts are no longer just and reasonable. Our *Mobile-Sierra* findings as to public utility sellers apply only when utilities seek to add stranded cost provisions or make other modifications related to stranded costs. Thus, if a utility with a *Mobile-Sierra* contract initiates a section 206 proceeding in which it seeks to modify contract provisions that do not relate to stranded costs, it will have to show that it is contrary to the public interest not to modify the contract.

As we stated in Order No. 888, the most productive way to analyze contract modification issues is to consider simultaneously both the selling public utility's claims, if any, that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and the customer's claim, if any, that the contract no longer is just and reasonable and therefore ought to be modified. We said that if a customer brings a claim in a section 206 proceeding to shorten or terminate a contract, the selling public utility must bring any stranded cost claim with respect to that customer in that section 206 proceeding. Our goal is to ensure that all of the issues expected to be raised by the parties when a customer departs a utility's generation system can be efficiently litigated in one proceeding. Therefore, we have similarly required that if the customer intends to claim that the notice or termination provision of its existing requirements contract is unjust and unreasonable, it must present that claim in any proceeding brought by the selling public utility to seek recovery of stranded costs. We disagree with American Forest & Paper's argument that it is a ''no-win'' situation if a customer seeking to modify a contract must present that claim in any stranded cost proceeding brought by the selling public utility. To the contrary, providing the customer to a *Mobile-Sierra* contract with the opportunity to demonstrate that its contract is no longer just and reasonable and that its term should be shortened or eliminated could be beneficial to the customer, notwithstanding the customer's potential stranded cost obligation. As we explained in the Rule:

> [G]iven the industry circumstances now facing us, both selling utilities and their customers ought to have an opportunity to make the case that their existing requirements contracts ought to be modified. By providing both buyers and sellers this opportunity, the Commission attempts to strike a reasonable balance of the interests of all market participants.[[664]]

In response to APPA's analysis of *Northeast Utilities,* it is true, as APPA asserts, that *Northeast Utilities* involved the Commission's initial review of a contract, not modification of a previously accepted and approved contract, and that the contract involved an affiliate transaction, while this rulemaking is targeted at arm's-length agreements. However, we do not believe that these differences bear on the precedential value of this case to the circumstances presented in the Rule. To the contrary, we believe that *Northeast Utilities* provides valuable guidance concerning application of the public interest standard where, as here, a failure to allow limited contract modification may harm the public interest by harming third parties.

We disagree with APPA's contention that the Commission should have applied the ''practically

[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.

[662] 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.

insurmountable'' standard from ''the classic 'low-rate' case, namely, *Papago*.''[665] As we have stated on several occasions, ''we do not interpret the public interest standard of review * * * as imposing on us a practically insurmountable burden in situations in which we are protecting non-parties to a contract.''[666] Additionally, we do not interpret the public interest standard as practically insurmountable in extraordinary situations such as this one where historic statutory and regulatory changes have converged to fundamentally change the obligations of utilities and the markets in which they and their customers will operate. In this circumstance, we believe the public interest test is met where the Commission determines that it is necessary to allow parties to seek contract amendments in order to protect the stability and financial integrity of the electric industry in general during the transition to competition as well as the interest of third parties affected by the transition. This type of situation simply was not addressed in *Papago*.

Congress has entrusted the Commission with the statutory responsibility to protect the public interest. As we explained in *Northeast Utilities Service Company:*[667]

> Protection of the 'public interest' provides the justification for the Commission's power to regulate public utilities under Part II [of the FPA]. Specifically, section 201(a) of the FPA declares 'that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest' and that federal regulation of matters related to generation (to the extent provided in Parts II and III of the FPA) and of the transmission and sale at wholesale of electric energy in interstate commerce 'is necessary in the public interest.'

Consistent with our statutory obligations under the FPA, the Commission has an overriding responsibility to protect non-parties affected by *Mobile-Sierra* contracts, including consumers, to ensure that matters entrusted to our jurisdiction function smoothly during the restructuring transition, and to fairly balance the interests of utilities and customers during the transition.[668] The ability to meet our overarching public interest responsibilities would be virtually precluded if we must apply a practically insurmountable standard of review before we can take action to address industry-wide transition issues.

Rehearing Requests Supporting Limited Transition Period

Several entities request rehearing of the Commission's decision not to establish a three-to five-year period within which stranded cost recovery could be raised. They assert that if the Commission truly views stranded investment as a transition process, the transition should not be an extended one.[669]

Commission Conclusion

The Commission will deny the requests for rehearing on this point. As we explained in Order No. 888, although we considered limiting the period within which stranded cost recovery could be raised, there is no uniform time remaining on requirements contracts executed on or before July 11, 1994.[670] As a result, any limitation on the period in which parties could propose amendments covering stranded costs, such as three years, would affect market participants unequally. Those with long terms remaining on their contracts could object that immediately addressing the issue would not be cost effective. A utility with a long remaining term might not even seek stranded cost recovery depending on the competitive value of its assets near the end of the contract term.[671] However, such a utility would invariably seek to preserve its option to seek stranded cost recovery if its failure to do so within a short period resulted in a waiver of its right to do so. Having determined that it is generally appropriate to leave in place existing requirements contracts, it is not then reasonable to create a time limitation on stranded cost recovery that would encourage a supplier to seek early termination in order to preserve its stranded cost recovery rights.

On this basis, we believe that we have adequately explained the rationale for our decision to allow stranded cost claims to be raised at any time prior to the termination of the contract, instead of within three to five years of the effective date of the Rule.

6. Recovery of Stranded Costs Caused by Retail-Turned-Wholesale Customers

In Order No. 888, we concluded that this Commission should be the primary forum for addressing the recovery of stranded costs caused by a retail-turned-wholesale customer.[672] We stated that if such a customer is able to reach a new generation supplier because of the new open access (through the use of a FERC-filed open access transmission tariff or through transmission services ordered pursuant to section 211 of the FPA), any costs stranded as a result of this wholesale transmission access should be viewed as ''wholesale stranded costs.'' We explained that there is a clear nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs and that, in these circumstances, this Commission should be the primary forum for addressing recovery of such costs.[673]

We said we will not be the primary forum for stranded cost recovery in situations in which an existing municipal utility annexes territory served by another utility or otherwise expands its service territory. We indicated that in these situations there is no direct nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs. The risk of an existing municipal utility expanding its territory was a risk prior

[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.

[666] 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).

[671] 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.

[673] 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.

to the Energy Policy Act and prior to any open access requirement.

Nevertheless, we did express concern that there may be circumstances in which customers and/or utilities could attempt, through indirect use of open access transmission, to circumvent the ability of any regulatory commission—either this Commission or state commissions—to address recovery of stranded costs. We reserved the right to address such situations on a case-by-case basis.

Rehearing Requests Opposing Retail-Turned-Wholesale Jurisdiction

A number of entities challenge the Commission's assertion that costs associated with retail-turned-wholesale customers would not be stranded but for the FERC-jurisdictional transmission access requirement. They assert that the condition precedent to municipalization is the operation of a state process, and thus that it cannot be the case that the recovery of costs caused by a retail-turned-wholesale customer is ''not subject to regulation by the States.'' They submit that such costs would not be stranded but for the action of state legislators or state regulators in granting authority for the customer's status change. They argue that any nexus that the Commission's authority under the FPA has to wholesale transmission services subsequently provided to the new wholesale customer is entirely derivative of the state's action.[674]

A number of entities argue that jurisdiction over costs that are stranded when a retail customer becomes a wholesale customer should be left to the states because the facilities used to provide retail service to these retail customers were subject to state jurisdiction and were included in retail rate base when the service was rendered.[675] They argue that because the Commission had no jurisdiction over the public utility facilities and costs incurred to serve retail-turned-wholesale customers, it has no jurisdiction to address those public utility costs if they become stranded. Thus, according to these entities, the conversion of the customer from retail to wholesale does not simultaneously effectuate a conversion of the costs from retail to wholesale.

AR Com and MO/KS Coms submit that jurisdiction over the costs incurred for historical retail customers does not shift unless the parties themselves make those costs a part of their new wholesale contract. NY Com submits that the Commission should recognize the states' jurisdiction to set the *level* of stranded costs associated with retail-turned-wholesale customers to be recovered in wholesale transmission rates set by FERC. FL Com asserts that state authorities are in a better position to assess the extent of stranded facilities and their costs, and that the Commission's involvement should be limited to that requested by a state by petition.

OH Com states that the Commission's position on stranded costs associated with retail-turned-wholesale customers invites second-guessing of state commission determinations and encourages forum shopping by introducing more than one stranded cost treatment within a single state jurisdiction. It expresses concern that utilities may seek to creatively disaggregate into generation, transmission, and distribution companies in ways to deliberately recast traditional retail relationships as wholesale in an effort to obtain favorable regulatory treatment of stranded costs.

IN Com submits that Order No. 888's treatment of stranded costs associated with retail-turned-wholesale customers will discourage state legislatures from making municipalization more available. VT DPS and Valero argue that the threat of a stranded cost surcharge will erect a new barrier to the formation of municipal utilities. They note that the Rule refers to one commenter's observation that, if Otter Tail could have made a stranded cost claim against the municipal utility that Elbow Lake planned to create, Otter Tail would not have needed to refuse to wheel and there would never have been an *Otter Tail* case. They submit that the Commission never addressed whether, or why, it believed the point to be wrong.

VT DPS and Valero also assert that the Rule represents a major inconsistency with prior Commission treatment of municipalization. They submit that the Commission historically promoted franchise competition between municipalities and utilities by holding tariff provisions that restrict such competition to be anticompetitive and unreasonable.[676]

American Forest & Paper submits that recovery of 100 percent of stranded costs caused by municipalization is inconsistent with the Commission's actions in the natural gas industry, where the Commission has encouraged competition at the retail level through competitive bypass and has not created barriers to competitive entry by imposing transition charges or exit fees on converting customers.[677]

Nucor objects that the Rule does not address the substantive findings, the common sense rationale, or the jurisdictional distinction drawn in *United Illuminating.*[678] It contends that the Commission's observation in Order No. 888 that there may not be a state regulatory forum for the recovery of stranded costs associated with retail-turned-wholesale customers and hence that the Commission should be the primary forum for addressing such stranded costs is flawed because there always is a state forum to address such cost recovery (the adequacy of the relief provided is a very distinct issue) and open access transmission does not and cannot cause retail competition to occur.[679]

Commission Conclusion

We will reject the requests for rehearing of our decision to be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. We find the requests for rehearing on this issue unpersuasive. While it may be the case, as some entities suggest, that state action is a condition precedent to municipalization, the rehearing petitions ignore the fact that the Rule covers situations in which open access is *also* a condition precedent to the municipalized customers leaving their existing supplier's system. Order No. 888 does not propose that the Commission be the primary forum for stranded cost recovery for all cases of municipalization. Instead, our holding is limited to those cases in which the new wholesale entity uses Commission-mandated transmission access to obtain new power supply on behalf of retail customers that were formerly supplied

[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*).

[679] *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).

power by the utility providing the transmission service.[680]

As we explained in Order No. 888, in such cases there is a direct nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of costs stranded as a result of this wholesale transmission access. Thus, the stranded costs associated with retail-turned-wholesale customers for which Order No. 888 provides an opportunity for recovery would not have been incurred *but for* the action of this Commission in requiring a utility to make unbundled transmission services available. In these cases, the former bundled retail customers of the historical supplying utility (now the bundled retail customers of the new municipal system) would not have obtained access to new power supply *but for* the Commission's order mandating transmission. Without the regulatory mandate to provide access, the utility would have indirectly continued sales to the same retail customers because the new municipal utility purchasing power on the retail customers' behalf would have had no way to reach other power suppliers. In this situation, there would be no stranded generation costs. In other words, the creation of a municipal utility intermediary to purchase power at wholesale would not, by itself, trigger stranded costs. Rather, it is the access from the historical supplier of the bundled retail customers that is the condition precedent to reaching other power suppliers and thereby triggering stranded costs. Therefore, there is a clear causal nexus between the stranded costs and the availability and use of the tariff *required by the Commission*.

Costs that are exposed to nonrecovery when a retail customer or a newly-created wholesale power sales customer ceases to purchase power from the utility and *does not* use the utility's transmission system to reach a new generation supplier (*e.g.*, through self-generation or use of another utility's transmission system) do not meet the definition of ''wholesale stranded costs'' for which the Rule provides an opportunity for recovery. Such costs are outside the scope of the Rule because such costs would not be stranded as a direct result of the new open access.

[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.

In response to the argument that conversion of a customer from retail to wholesale would not simultaneously effectuate a conversion of the costs from retail to wholesale, we believe this argument confuses the issue. We note that we have defined stranded costs as wholesale or retail on the basis of whether wholesale or retail open access is the cause of the costs being stranded, not on the basis of the original retail or wholesale characteristic of the costs. Thus, even though costs may have been originally incurred as retail-related costs, the precipitating event that results in such costs being stranded in the retail-turned-wholesale customer scenario is the use by the new wholesale customer of the Commission-mandated tariff. When a customer is able to use the Commission-required tariff to reach another generation supplier, it causes the utility to incur an economic cost in providing transmission service that is equal to the foregone revenues that the utility reasonably expected to receive under a state regulatory regime. Thus, because of the causal nexus between the use of a former supplying utility's Commission-mandated transmission tariff and the potential for foregone revenues by that utility as a result of the Commission-required access, the costs stranded by a retail-turned-wholesale customer are properly viewed as economic costs that are jurisdictional to this Commission.

In response to those entities that express concern that the Commission's position on stranded costs associated with retail-turned-wholesale customers invites second-guessing of state commission determinations, we emphasize that we have assumed primary authority to address such costs only in a limited category of cases where there is a direct nexus between the availability of Commission-required open access and the stranding of costs when the former customer uses the former supplying utility's transmission system (through its open access tariff or a section 211 order) to reach a new supplier. We indicated in Order No. 888 that if the state has permitted any recovery from departing retail-turned-wholesale customers, such amount will not be stranded for purposes of this Rule. We will deduct that amount from the costs for which the utility will be allowed to seek recovery under this Rule from the Commission. In so doing, however, we are not second-guessing the states as to what a utility may recover under state law. Additionally, we will give great weight in our proceedings to a state's view of what might be recoverable.

We also reject the argument that the Commission's position on stranded costs associated with retail-turned-wholesale customers encourages forum shopping. To the contrary, as we said in Order No. 888, to avoid forum shopping and duplicative litigation of the issue, we expect parties to raise claims before this Commission in the first instance. We believe that this Commission should be the primary forum because, without the open access provided by the Rule, the new municipal utility would not be able to reach a new supplier and, as a result, would not cause the utility to incur stranded costs (as defined in this Rule).

We reject as misplaced arguments that the Rule represents a major inconsistency with the Commission's historical promotion of franchise competition between municipalities and utilities and that it will discourage municipalization.[681] It continues to be the Commission's policy to encourage competition. Indeed, the goal of Order No. 888 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. However, the purpose of the stranded cost policy is neither to encourage nor to discourage municipalization, but rather to facilitate a fair transition to competition and to ensure stability in the industry during that transition. As we discuss elsewhere in this order, we believe that this Commission must address the recovery of the costs of moving from a monopoly-regulated regime to one in which all sellers can compete on a fair basis and in which electricity is more competitively priced. On this basis, we believe that if a new wholesale entity such as a municipal utility uses Commission-required open access to reach a new supplier on behalf of its retail customers (previously retail customers of the former supplier), the former supplying utility should be given an opportunity to recover legitimate, prudent and verifiable costs that it

[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.

incurred under the prior regulatory regime to serve that customer.

In response to American Forest & Paper's argument that recovery of 100 percent of stranded costs caused by municipalization is inconsistent with the Commission's policy in the natural gas industry of allowing competitive bypass without imposing transition charges or exit fees on converting customers, we note that industrial gas customers who bypass a local distribution company's (LDC) facilities do not escape transition costs quite so easily as suggested by American Forest & Paper. It is true that, when the end user bypasses the LDC to reach an interstate pipeline different from the pipeline serving the LDC, the Commission views the bypass as a risk of competition from which the LDC should not be shielded.[682] However, when the end user bypasses the LDC to reach the same interstate pipeline that serves the LDC, the Commission may take certain actions to minimize adverse effects on the LDC and its remaining customers.[683] Moreover, an end user that bypasses an LDC to reach the same pipeline that serves the LDC would, in any event, be allocated a share of the pipeline's gas supply realignment costs (if any), since those costs are allocated based on current contract demand (or usage).[684] Accordingly, we see no inconsistency between our bypass policy for the natural gas industry and Order No. 888's treatment of stranded costs associated with retail-turned-wholesale customers. Similar to our refusal to shield LDCs from the adverse effects of an end user's bypass to reach a different pipeline than serves the LDC, Order No. 888 does not provide an opportunity for stranded cost recovery where a retail-turned-wholesale customer uses another utility's transmission system to reach a new supplier. As we note above, the opportunity for recovery of stranded costs associated with retail-turned-wholesale customers is limited to those cases in which the former retail customer obtains (either directly or through another wholesale transmission purchaser) unbundled transmission services from its former supplying utility. In the case of an end use customer bypassing the LDC to reach the same pipeline that serves the LDC, the end use customer would similarly be allocated a share of the pipeline's gas supply realignment costs. As a result, American Forest & Paper's attempt to rely on the Commission's gas bypass policy is misplaced.

We also disagree with those entities that argue that the Commission has failed to adequately distinguish Order No. 888's treatment of stranded costs associated with retail-turned-wholesale customers with the Commission's decision in *United Illuminating.* As we stated in Order No. 888, we recognize that we took a different approach to stranded cost recovery associated with retail-turned-wholesale customers in *United Illuminating,* where we suggested that state and local regulatory authorities or the courts should be able to provide an adequate forum to address retail franchise matters, including recovery of stranded costs caused by municipalization, but said we would consider revisiting the question if United Illuminating could demonstrate the lack of a forum.[685] However, we explained that since the issuance of that decision we have had an opportunity to re-analyze the nature of the stranded cost problem when a retail customer becomes a wholesale customer, including the potential that there might not be a state regulatory forum for recovery of such costs. In these circumstances, we have determined that where such costs are stranded as a direct result of Commission-mandated wholesale transmission access, these costs should be viewed as costs of the transition to competitive wholesale bulk power markets and this Commission should be the primary forum for addressing their recovery.

In response to Nucor's objection that there always is a state forum to address stranded cost recovery associated with retail-turned-wholesale customers, with the adequacy of the relief being a distinct issue, we clarify that our primary concern in retail-turned-wholesale situations is not whether there is an adequate state regulatory forum for the recovery of stranded costs associated with retail-turned-wholesale customers. Rather, our primary concern is that wholesale customers (whether or not formerly retail) should be responsible for the costs incurred to meet their power needs that are stranded when they use the wholesale transmission ordered by this Commission to reach new suppliers. Our decision to be the primary forum in the case of stranded costs associated with retail-turned-wholesale customers is based on the causal nexus between regulatory-mandated wholesale transmission access and the stranding of costs when a new municipal utility uses such access to obtain new power supply on behalf of retail customers previously served by the former supplying utility.

Rehearing Requests Seeking Expansion of Retail-Turned-Wholesale Jurisdiction

Other entities seek rehearing of the Commission's decision not to be the primary forum for stranded cost recovery in situations in which an existing municipal utility annexes territory served by another utility or otherwise expands its service territory.[686] A number of them argue that the loss of existing retail customers through municipal annexations or expansions is no different from the loss of retail customers through new municipalization because existing municipal systems are likely to use Commission-jurisdictional open access transmission to obtain resources to supply power to the annexed loads.[687] They submit that, just as with newly-municipalized customers, such costs would not be stranded but for the action of this Commission.

Some of these entities express concern that the Rule will encourage retail-turned-wholesale transactions to be undertaken as annexations rather than through the formation of new entities to avoid stranded costs. [688] Public Service Co of CO contends that Order No. 888, in conjunction with the Commission's section 211 order in American Municipal Power Ohio, Inc.,[689] may facilitate municipal annexations by enabling municipal systems to serve new territory through the establishment of second delivery points.

Coalition for Economic Competition and Puget also argue that the Commission must consider stranded

[682] Texas Gas Transmission Corporation, 65 FERC ¶ 61,275 (1993).

[683] 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).

[684] *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.

[687] *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.

[689] 74 FERC ¶ 61,086, *final order directing transmission service*, 76 FERC ¶ 61,265 (1996).

costs that arise from municipal expansion in order to satisfy its statutory obligation under the FPA to ''set just and reasonable'' rates. They contend that there is no justification for charging one rate to former retail customers taking transmission services through a new municipal utility and another rate to those taking service through municipal annexation or through use of another utility's transmission system.

PSE&G suggests that the distinction between new municipalization on the one hand and municipal annexation or expansion on the other hand may lead to unnecessary controversy and litigation as entities wrangle over whether a given expansion/annexation is really an expansion or a municipalization. It says that a situation could arise where a municipality serves one town in order to serve thousands of additional customers in a second town. According to PSE&G, it is not clear from the Rule whether the Commission would consider this an expansion of a municipality's service territory or a new municipalization.

Puget submits that the stranded cost recovery mechanism must not be subject to being frustrated by simple artifices such as having the new supplier (instead of the departing customer) request and contract for transmission service. SoCal Edison seeks clarification of the Commission's authority to mandate stranded cost recovery if 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). It asks the Commission to clarify that such a transaction effectively constitutes a municipalization, not an expansion of a service territory, and that the Commission, under FPA section 211, can compel the recovery of stranded costs by having the ''new'' jurisdictional utility assess a stranded cost charge and pass the revenues on to the utility from whose system the customer departed.

SoCal Edison seeks several additional clarifications. It states that it understands that the Commission's primary forum status in no way prevents or interferes with a state's authority to order stranded cost recovery from departing retail customers. If this is not the case, SoCal Edison seeks rehearing on this issue. SoCal Edison also asks the Commission to clarify that the Commission retains the discretion to defer to a state stranded cost calculation methodology if appropriate to do so on the facts of a particular case.

Commission Conclusion

We have carefully reviewed the arguments made by petitioners seeking rehearing of our decision not to be the primary forum for stranded cost recovery in the case of municipal annexations. Based on that review we have decided to reconsider our decision. This conclusion is based in large part upon the very significant similarities between the creation of a *new* municipal utility system (also referred to as municipalization) and the expansion of an *existing* municipal utility system (*e.g.*, through annexation of additional retail service territory). We recognize that the *same nexus* to Commission-required transmission access that forms the basis for our decision to allow a utility to seek stranded cost recovery in cases of new municipalization—use of the former supplying utility's transmission system—is likely to be present in some cases of municipal annexation. In the case of both new municipalizations and annexations, the bundled retail customers of a local utility become the bundled retail customers of a municipal utility (in one case a new municipal utility, in the other an existing municipal utility) *that will use the transmission system of the retail customers' former supplier in order to access other suppliers.*

As we explain above, 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 the retail customers. It 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. The same analogy applies to newly-annexed customers; they become ''new'' wholesale customers in the sense that the wholesale entity obtains transmission and new power supply on their behalf.

Accordingly, we clarify that this Commission will be the primary forum for addressing the recovery of stranded costs if an existing municipal utility uses the transmission system of its annexed retail customers' former supplier to access new suppliers to serve the annexed load. As long as Commission-required transmission access (the former supplier's open access tariff or transmission services ordered under FPA section 211) is the vehicle that enables an existing municipal utility to obtain power supplies to serve annexed loads, we believe that any costs stranded as a result of this wholesale transmission access are properly viewed as economic costs that are jurisdictional to this Commission. In such a case, the bundled retail customers that are annexed by an existing municipal utility would, through the municipal utility, use the transmission system of their former supplier to obtain access to new supplies and thereby expose their former supplier to non-recovery of prudently incurred costs. As in the case of new municipal systems that use the transmission system of their retail customers' former supplier, such costs would not be stranded *but for* the action of this Commission in requiring a utility to make unbundled transmission services available.[690]

Just as we will not be the primary forum for stranded cost recovery for *all* new municipalizations, so also we will not be the primary forum for stranded cost recovery for *all* cases of municipal annexation. Instead, our holding is limited to those cases in which the existing municipal system uses Commission-mandated transmission access from the annexed customers' former supplying utility to obtain power from a new supplier. Costs that are exposed to nonrecovery when an existing municipal utility *does not* use the transmission system of the retail customers' former supplier to reach a new generation supplier (*e.g.*, through self-generation or use of another utility's transmission system) do not meet the definition of ''wholesale stranded costs'' for which the Rule provides an opportunity for recovery. Such costs are outside the scope of the Rule because such costs would not be stranded as a direct result of Commission-required transmission access.

[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.

We reject as misplaced the argument that the Commission, by failing to address costs that arise if a municipal utility (whether a new municipal utility or an existing municipal utility that annexes additional retail customer territory) does not use the historical supplying utility's transmission system, has not met its statutory obligation to ''set just and reasonable'' rates. The Commission in this rulemaking has not determined any utility's just and reasonable rates. Further, Order No. 888 does not by its terms bar the recovery of costs that do not result from the use of Commission-required transmission access. Utilities may, as before, seek recovery of such non-open access-related costs on a case-by-case basis in individual rate proceedings. The Commission will not prejudge those issues here.

As we indicated in Order No. 888, we also are concerned that there may be circumstances in which customers and/or utilities could attempt, through indirect use of open access transmission, to circumvent the ability of any regulatory commission—either this Commission or state commissions—to address recovery of stranded costs.[691] We reiterate that we reserve the right to address such situations on a case-by-case basis.

We share the concern expressed by Puget that a retail-turned-wholesale customer should not be allowed to avoid any stranded cost obligation that it may have under Order No. 888 simply by having its new supplier be the entity that requests and contracts for transmission service from the former supplying utility. We clarify that the opportunity for recovery of stranded costs associated with retail-turned-wholesale customers under Order No. 888 applies if the transmission system of the former supplier is used to transmit the newly obtained power supplies to the departing retail customer, regardless of whether the customer *or* its new supplier is the actual entity that requests and contracts for the unbundled transmission service. We have revised the definition of ''wholesale stranded cost'' in section 35.26(b)(1)(ii) accordingly to include the situation in which the retail customer subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of the former supplying utility.

We clarify in response to SoCal Edison's request that our decision to be the primary forum for recovery of stranded costs from retail-turned-wholesale customers is not intended to prevent or to interfere with the authority of a state to permit any recovery from departing retail customers, such as by imposing an exit fee prior to creating the wholesale entity. As we indicated in Order No. 888, if the state has permitted any such recovery from a departing retail-turned-wholesale customer, that amount will not in fact be stranded. Accordingly, we will deduct that amount from the costs for which the utility will be allowed to seek recovery from this Commission.[692]

We clarify in response to SoCal Edison's request that the Commission has the discretion to defer to a state stranded cost calculation methodology. However, because we recognize that state retail access plans may present questions that need to be addressed on a case-by-case basis, we will consider whether to exercise that discretion on a case-by-case basis.

7. Recovery of Stranded Costs Caused by Retail Wheeling

In Order No. 888, we concluded that both this Commission and the states have the legal authority to address stranded costs that result when retail customers obtain retail wheeling in order to reach a different generation supplier, and that utilities are entitled, from both a legal and a policy perspective, to an opportunity to recover all of their prudently incurred costs.[693] We explained that this Commission's authority to address retail stranded costs (*i.e.*, stranded costs associated with retail wheeling customers) is based on our jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, and that the authority of state commissions to address retail stranded costs is based on their jurisdiction over local distribution facilities and the service of delivering electric energy to end users. Because it is a state decision to permit or to require the retail wheeling that causes stranded costs to occur, we decided we generally will leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. The only circumstance in which we will entertain requests to recover stranded costs caused by retail wheeling is when the state regulatory authority[694] does not have authority under state law to address stranded costs when the retail wheeling is required. In such a case, we will permit a utility to seek a customer-specific surcharge to be added to an unbundled transmission rate.

We noted that most states have a number of mechanisms for addressing stranded costs caused by retail wheeling. We indicated that rates for services using facilities used in local distribution to make a retail sale are state-jurisdictional, and that states will be free to impose stranded costs caused by retail wheeling on facilities or services used in local distribution. We also said that states may use their jurisdiction over local distribution facilities or services to recover so-called stranded benefits.

We stated that we believe our approach to stranded costs associated with retail wheeling customers represents an appropriate balance between federal and state interests that ensures that the rates for transmission in interstate commerce by public utilities (except in a narrow circumstance) will not be burdened by retail costs.

We expressed concern about the cost-shifting potential in a holding company or other multi-state situation, where denial of retail stranded cost recovery by a state regulatory authority could, through operation of the reserve equalization formula in a Commission-jurisdictional intra-system agreement, inappropriately shift the disallowed costs to affiliated operating companies in other states. We said that we will deal with such situations if they arise pursuant to public utility filings under section 205 or complaints under section 206. Thus, the need to amend a jurisdictional agreement to prevent stranded costs associated with retail wheeling customers from being shifted to customers in other states will be addressed on a case-by-case basis. We encouraged the affected state commissions in such situations to seek a mutually agreeable approach to this potential problem. If such a consensus solution resulted in a filing to modify a jurisdictional agreement, we indicated that we would accord such a proposal deference, particularly if other interested parties support the filing. In the event that the state commissions and other interested parties cannot reach consensus that would prevent cost shifting, we said that the Commission would ultimately have to resolve the

[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.

[694] ''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.

appropriate treatment of such stranded costs.

Rehearing Requests Opposing Any Commission Involvement in Stranded Costs Associated With Retail Wheeling Customers

A number of entities dispute the Commission's statement that both it and the states have the legal authority to address stranded costs that result from retail wheeling. Central Illinois Light contends that the Commission's claim of dual jurisdiction is inconsistent with *FPC* v. *Southern California Edison Company*.[695] It says that the court in that case recognized that Congress meant to draw a bright line easily ascertained between state and federal jurisdiction, making unnecessary case-by-case analysis. Central Illinois Light asserts that the Commission has stepped over the bright line into the states' exclusive jurisdiction over retail rates.

IA Com seeks rehearing of the Commission's assertion of concurrent jurisdiction with state authorities over stranded costs associated with retail wheeling customers on the ground that it is based on the Commission's erroneous assertion of jurisdiction over unbundled retail transmission.

IL Com says that regardless of whether the Commission's claim of jurisdiction over retail transmission is upheld, the Commission's ruling that there is joint jurisdiction over retail stranded costs is in error. According to IL Com, the Commission has no authority over such stranded costs. IL Com also disputes the Commission's characterization of the derivation of state authority to address such stranded costs. It says that state commission authority does not derive only from states' jurisdiction over local distribution facilities and the service of delivering electric energy to end users. IL Com submits that state commission authority to address retail stranded costs derives from the existence of state commission jurisdiction over the facilities and costs at the time of their incurrence.

A number of entities contend that Commission jurisdiction over transmission facilities used in interstate commerce does not give it jurisdiction over stranded investment in retail generating assets.[696] Several argue that the fact that a retail wheeling customer might need transmission access from its former supplier does not change the character of the costs that are stranded. They maintain that retail stranded costs are not costs of providing unbundled transmission service, but are costs associated with providing what was formerly bundled retail service, over which the Commission has no jurisdiction.[697]

Several entities argue that it is solely the action of the state that allows a given utility's retail customers to seek alternative sources of supply; therefore, there is no nexus between the Commission's wholesale transmission rule and any costs that might be stranded by a state-established customer choice regime.[698]

A number of entities submit that the provision of FPA section 201 that federal regulation is ''to extend only to those matters which are not subject to regulation by the States'' bars any attempt by the Commission to displace or supplant an admittedly legitimate exercise of state authority over retail stranded costs.[699] NASUCA submits that all state commissions have the authority to establish just and reasonable rates for the retail electric utilities in their respective jurisdictions.[700] It maintains that only state regulators are in a position to rule on the treatment of costs that were allowed in retail rates pursuant to state laws; the Commission has no knowledge or expertise regarding the specific state legal frameworks in which these costs were included in rates. NY Com argues that the Commission does not have jurisdiction to determine the rate treatment of costs devoted to retail service and, thus, lacks authority to allow recovery if a state decides not to do so.

VA Com argues that section 201(b)(1) of the FPA restricts the Commission's jurisdiction to wholesale sales. It says that a departing retail customer remains a retail customer, regardless of the supplier. VA Com concludes that no portion of the transaction is a wholesale sale, and that there are no wholesale costs associated with a retail wheeling transaction.[701]

A number of entities seek rehearing of the Commission's decision that it will entertain stranded cost claims when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required.[702] NARUC submits that Congress did not intend the Commission to become involved in adjudicating legal questions regarding the breadth of state law authority granted state commissions by their legislatures. NARUC expresses concern that the Commission would second-guess a state cost recovery determination and promote forum shopping. Once a balance has been struck at the state level concerning the terms of restructuring, NARUC submits that it is inconceivable that the Commission would have either the desire or authority to second-guess a state's legislative and regulatory processes.

Several entities object that the Commission effectively would authorize recovery of stranded costs associated with a retail wheeling customer if a state legislature withholds from the state regulatory agency the authority to approve stranded cost recovery.[703] They submit that just because a state has not given its regulatory commission the authority to impose stranded costs in the case of retail wheeling does not confer jurisdiction on the Commission to impose such charges. They contend that the state legislature should be the final arbiter of state policy. IL Com submits that if a state legislature chooses not to give its state commission the authority to act on stranded costs, ''that can be taken as a clear indication that the state's legislature most certainly does *not* want FERC to address them.'' [704] Central Illinois Light objects that the Commission has offered no reason why it will accept the decision

[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.

[697] *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.

[700] 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.

[704] IL Com at 38 (emphasis in original).

of the regulatory agency, but not that of the legislature.

AMP-Ohio and Cleveland ask the Commission to clarify that its deference to the determinations of the states is to the authority of the states as exercised through state legislative bodies (and other political subdivisions with legislative authority) as well as to state regulatory bodies. They submit that if the state legislature, or a local government acting in accordance with its authority, enacts retail wheeling legislation that expressly limits the ability of its regulatory body to permit recovery of stranded costs, even barring all such recovery, the Commission should not become involved.

Several entities ask the Commission to clarify that Order No. 888 does not permit utilities to apply to the Commission for recovery of stranded costs associated with a retail wheeling customer when a state regulatory authority has ''addressed'' a request for the same stranded costs but has not allowed 100 percent recovery.[705] ELCON gives two hypothetical examples to which it asks the Commission to respond: one where a state regulatory authority possesses full stranded cost recovery authority but allows only 50 percent recovery; the other where the state legislature provides the state regulatory authority by statute with the power to permit recovery of up to 50 percent of identified stranded costs.

Commission Conclusion

We reaffirm our conclusion that both this Commission and the states have the legal authority to address stranded costs that result when retail customers obtain retail wheeling in interstate commerce from public utilities in order to reach a different generation supplier, but that, because it is a state decision to permit or require the retail wheeling that causes retail stranded costs to occur, we will leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. The only circumstance in which we will entertain requests to recover stranded costs caused by retail wheeling is when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required.

We will reject the requests for rehearing that oppose any Commission involvement in stranded costs associated with retail wheeling customers. We disagree with those entities that challenge our conclusion that both this Commission and the states have the legal authority to address stranded costs that result from retail wheeling (variously described by those entities as dual, concurrent, or joint jurisdiction). The Commission explained in detail in Order No. 888 the legal basis for concluding that this Commission and the state commissions each have jurisdiction over separate aspects of a retail wheeling transaction.[706] This Commission has jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities. State commissions have jurisdiction over local distribution facilities and the service of delivering electric energy to end users. Based on our respective jurisdictions over separate aspects of the retail wheeling transaction, we believe either has the authority to provide the former supplying utility with an opportunity to recover costs stranded when the departing customer uses retail transmission in interstate commerce to reach a new supplier, but that here, unlike the retail-turned-wholesale scenario, the state commission should be the primary forum because these costs are stranded by the action of the state. We would act only if the primary forum is not available. We have made a policy decision that this Commission will step in to fill a regulatory ''gap'' that could result in no effective forum under which utilities would have an opportunity to seek recovery of prudently incurred costs.

Several entities argue that the Commission does not have jurisdiction over stranded investment in retail generating assets, that use of Commission-jurisdictional transmission does not change the character of the costs that are stranded, that stranded costs associated with retail wheeling customers are not costs of providing unbundled transmission service, but are costs associated with providing what was formerly bundled retail service, and that only state regulators are in a position to rule on the treatment of costs that were allowed in retail rates pursuant to state laws. While we agree that stranded costs associated with retail wheeling are costs that are retail in character in the sense that they are in retail bundled rates and become stranded as a result of retail wheeling required by the state commission, we do not believe this precludes the Commission from exercising jurisdiction in the limited circumstances of the Rule.

As an initial matter, we note that there are rarely separate retail and wholesale generating facilities. Retail customers and wholesale requirements customers get energy from the same facilities, each buying a ''slice of the system.'' Typically all generating assets go into both the retail and the wholesale rate bases for determining retail and wholesale rates. Rates are determined by allocating the total generating costs among customer classes. The parties confuse the issue before us to the extent they suggest that state commissions, not this Commission, have ''jurisdiction'' over certain ''costs.'' Neither the state commissions nor this Commission has exclusive jurisdiction over ''costs.'' Each regulatory authority has jurisdiction to determine ''rates'' for services subject to its jurisdiction and, in determining rates, may take into account all of the costs incurred by the utility. Under historical cost-of-service ratemaking, each regulatory authority, in exercising its respective *ratemaking* jurisdiction, reviews the *total* costs incurred by a utility to provide service and makes its separate and independent determination of what costs may be recovered through rates within its jurisdiction.[707] Generating costs continually shift between retail and wholesale rates over time.[708]

[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.

[708] 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.

More importantly, both the state commission and this Commission have a responsibility to oversee the financial health of the utilities we regulate. Each has jurisdiction to make judgments about recovery of the costs of the assets in the utility's total rate base. Utilities are entitled to a regulatory forum that can adjudicate claims that they are or are not entitled to recovery of costs incurred regardless of the initial retail or wholesale ''character'' of those costs, and we believe we have the authority and obligation to fill a regulatory ''gap'' that could occur.[709]

In response to the argument that it is solely the action of the state that allows a retail customer to seek alternative sources of supply and, as a result, there is no nexus between the Commission's wholesale transmission rule and any costs that might be stranded by a state-established customer choice regime, we agree. Indeed, as we indicate in Order No. 888, we decided to leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling (with a limited exception) because it is a state decision to permit or require the retail wheeling in the first instance that causes retail stranded costs to occur. Our determination, as explained above, is to fill any regulatory gap that arises as a result of interstate wheeling. We believe that it is necessary for the Commission to act as a backstop in this limited instance to ensure that costs stranded as a result of retail wheeling do not go unrecovered because the state regulatory authority lacks the authority under state law to address such costs. At the same time, as we stated in Order No. 888, we believe that most states have a number of mechanisms for addressing stranded costs caused by retail wheeling. We emphasize that this Rule is not intended to preempt the exercise of any existing state authority with respect to the assessment of a stranded cost or stranded benefits charge on a retail customer that obtains retail wheeling.

In response to arguments that the Commission's decision will result in second-guessing or interfering with a state's legislative processes and decisions, we believe these arguments are premature. As a general matter, we do not expect that our decision to be a backstop will interfere with legislative decisions that specifically address stranded cost matters and the scope of the state regulatory authority's authority in determining stranded costs. If states or parties to a retail stranded cost recovery case brought before this Commission believe that a Commission decision on the issue would interfere with state legislative decisions, they should raise their arguments, and support therefore, at that time.

We clarify that Order No. 888 does not permit utilities to seek recovery from the Commission of stranded costs associated with retail wheeling customers if a state regulatory authority with authority to address retail wheeling stranded costs has in fact addressed such costs, regardless of whether the state regulatory authority has allowed full recovery, partial recovery, or no recovery.

Rehearing Requests Supporting Broader Jurisdiction Over Stranded Costs Associated With Retail Wheeling Customers

A number of entities seek rehearing of the Commission's decision not to serve as a backstop for all stranded costs associated with retail wheeling customers. Some assert that the Commission has the legal authority to address independently stranded costs that arise from retail wheeling and that the Commission cannot lawfully abdicate or delegate such authority to the states.[710] Coalition for Economic Competition submits that the Commission correctly concluded that it has jurisdiction over retail transmission rates, terms and conditions and the authority to address retail wheeling stranded costs. Thus, it argues that the Commission is without the power to make a ''policy determination'' that results in the Commission not exercising its legal authority over stranded costs associated with retail wheeling customers. It asserts that, just as the Commission recognizes that it ''cannot simply turn over its jurisdiction'' to the states to determine facilities subject to Commission jurisdiction,[711] the Commission cannot turn over its jurisdiction to establish stranded cost charges that it correctly determined it has the authority to establish. Coalition for Economic Competition argues that the Commission should adopt a stranded cost recovery policy similar to the policy the Commission has adopted with respect to the determination of state/federal jurisdiction, whereby the Commission would defer to state stranded cost determinations so long as they are consistent with the Commission's policy.

Utilities For Improved Transition argues that the Commission's authority over public utility rates for the transmission of electric power, both wholesale and retail, is plenary and exclusive. As a result, it submits that the Commission may not avoid responsibility for costs stranded by transmission of retail power.[712] Illinois Power contends that Congress did not authorize the Commission to reject jurisdictional rate filings whenever the Commission regards the state commissions as a more convenient or appropriate forum.

EEI and the Coalition for Economic Competition contend that virtually all retail stranded costs can only occur through the vehicle of Commission-jurisdictional transmission in interstate commerce. They submit that the Commission, having recognized the clear nexus between FERC-jurisdictional transmission and stranded costs in the retail-turned-wholesale context, cannot fail to recognize the same clear nexus in the retail wheeling context.

Utilities For Improved Transition says that it is legally immaterial whether stranded costs are caused by the Commission's ordering the transmission or the states' doing so; the determining factor is who has the jurisdiction to make the rates for the service, not who has the jurisdiction to order the service.

Coalition for Economic Competition and Utilities For Improved Transition contend that the Commission must consider stranded costs that arise from retail wheeling in order to satisfy its statutory obligation under the FPA to ''set just and reasonable'' rates. Coalition for Economic Competition maintains that FPA sections 201, 205 and 206 do not give the Commission the flexibility to allow stranded costs in certain jurisdictional wheeling rates (*e.g.*, wholesale wheeling and new municipalizations) but to exclude them from other jurisdictional wheeling rates (*e.g.*, retail wheeling, municipal

[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.

[711] 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.

annexation, and bypass).[713] Utilities For Improved Transition says that the just and reasonable standard requires the Commission to backstop the states to ensure that there is full stranded cost recovery. It objects that Order No. 888's disposition of jurisdiction creates a problem of cross-class discrimination (wholesale versus retail) and inter-class discrimination (some retail versus the remainder of the retail).

Coalition for Economic Competition further argues that the Commission's failure to address all stranded costs associated with retail wheeling customers will result in an improper taking under the Constitution.[714] It also argues that the Commission is not permitted to disregard its findings in Order No. 888 which, according to Coalition for Economic Competition, ''inexorably'' lead to the conclusion that Commission action on ''all'' stranded costs (including retail wheeling, municipal annexation, and bypass stranded costs) is required.[715]

Illinois Power argues that the FPA does not authorize the Commission to discriminate among utilities based on the state of their residence, and that the Commission must allow all utilities to seek interstate rate recovery of just and reasonable retail stranded costs. Illinois Power asserts that the Rule will lead to the absurd, unduly discriminatory result that utilities located in states whose legislatures have failed to provide for stranded cost recovery will be better off than those located in states that provide for only limited stranded cost recovery. It supports use of the Commission's statutory authority to establish a uniform, national method for retail stranded cost recovery.

Coalition for Economic Competition also contends that the Commission's decision to let the states deal with retail stranded costs is arbitrary and capricious because the Commission failed to consider the arguments that stranded cost opponents will make before state commissions, such as that a state lacks jurisdiction to impose stranded cost charges or that the state imposition of such charges may be preempted or found to be an undue burden on interstate commerce. It further argues that the Commission's reliance on state jurisdiction over the service of delivering electric energy to the end user does not reflect reasoned decisionmaking. It submits that the Commission has failed to consider that the sale of electric energy may take place outside of the state into which the energy is transmitted, in which case the state commission may have no jurisdiction over either the sale or the transmission of the energy and, accordingly, no authority to consider stranded costs.

A number of entities ask the Commission to act on requests for retail stranded cost recovery when the state commission lacks authority *or* has authority to order recovery, but has declined to do so or has only allowed partial recovery.[716]

Lastly, TX Com notes that section 35.26(d) (dealing with recovery of retail stranded costs) refers only to public utilities. It suggests that the omission of a reference to transmitting utilities appears to be inadvertent and should be corrected.

Commission Conclusion

The Commission will reject the requests for rehearing of our decision not to assume a backstop role for all stranded costs associated with retail wheeling customers. We explained in Order No. 888 that commenters that describe our action as an unlawful abdication or delegation of authority misconstrue the nature of our decision to leave stranded costs associated with retail wheeling customers (with a limited exception) to state regulatory authorities.[717] We have not ''abdicated'' or ''delegated'' to state regulatory authorities our jurisdiction over the rates, terms, and conditions of retail transmission in interstate commerce; if retail transmission in interstate commerce by a public utility occurs, public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205.[718] Instead, we have made a policy determination that the recovery of stranded costs associated with retail wheeling customers—an issue over which either this Commission or state commissions could exercise authority by virtue of their jurisdiction over retail transmission in interstate commerce and over local distribution facilities and services, respectively—is primarily a matter of local or state concern for which the primary forum should be the state commissions. However, if the state regulatory authority does not have authority under state law to be the forum to address stranded costs when the retail wheeling is required, then we will entertain requests to recover such costs. As we explain above in response to the rehearing petitioners that oppose any Commission involvement in stranded costs associated with retail wheeling customers, we have made a policy decision that this Commission will step in to fill a regulatory ''gap'' that could result in no effective forum under which utilities would have an opportunity to seek recovery of prudently incurred costs.[719]

We disagree with Coalition for Economic Competition's argument that our findings in Order No. 888 ''inexorably'' lead to the conclusion that Commission action on ''all'' stranded costs (including retail wheeling and bypass stranded costs) is required, much less that the Commission has ignored the findings in Order No. 888. To the contrary, as we explain in Section IV.J.1, it is not the purpose of this Rule to allow utilities an opportunity to seek to recover ''all'' uneconomic costs that might be stranded when a customer leaves its utility supplier. We have fully explained our reasons for adopting an approach that, for purposes of stranded cost recovery from wholesale transmission customers, relies on the nexus between stranded costs and the use of transmission tariffs required by this Commission and, for purposes of stranded cost recovery from retail customers, recognizes state commission jurisdiction but fills potential regulatory gaps that could arise in the transition to new market structures.

[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).

[715] 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.

[718] 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.

[719] 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.

We disagree with those entities that contend that the Commission must consider retail stranded costs in order to satisfy our statutory obligation under the FPA to set just and reasonable rates. In determining just and reasonable rates for jurisdictional transmission service, which currently are determined on a cost basis, the Commission satisfies its statutory obligation under the FPA by allowing utilities an opportunity to recover their prudently incurred costs plus a reasonable rate of return. As we have explained above, this may include the costs of use of the physical transmission system, as well as economic costs incurred by the utility when it provides transmission service (*e.g.,* stranded costs). However, in situations in which a state regulatory authority has the authority to address recovery of retail stranded costs, there is no regulatory ''gap,'' and there is no obligation for this Commission to provide a second opportunity for recovery.[720]

We reject arguments that FPA sections 201, 205 and 206 do not give the Commission the flexibility to allow stranded costs in certain jurisdictional wheeling rates (wholesale wheeling and new municipalizations) but to exclude them from other jurisdictional wheeling rates (retail wheeling in interstate commerce and use of another utility's transmission tariff), and that this policy somehow makes rates discriminatory. Recovery of this type of cost through a transmission rate is obviously not the norm, but is necessitated by the need to deal with the transition costs associated with this Rule. As discussed in detail in the Rule, the Commission has carefully balanced the interests of utilities as well as customers in concluding that the opportunity for stranded cost recovery through transmission rates should be permitted in only two general circumstances: (1) in the case of wholesale stranded costs, where there is a direct nexus to Commission-required transmission access; and (2) in the case of retail stranded costs, where there otherwise would be a regulatory gap because a state regulatory authority lacks authority under state law to address stranded costs at the time that retail wheeling is required. We see nothing in the FPA that precludes us from exercising this flexibility and, indeed, the parties have not pointed to anything that, in our opinion, precludes us from exercising this discretion.

We reject the argument that virtually all stranded costs associated with retail wheeling customers can occur only through the vehicle of Commission-jurisdictional transmission in interstate commerce, and therefore, that the same nexus between FERC-jurisdictional transmission and stranded costs that exists in the retail-turned-wholesale context is present in the retail wheeling context. We also disagree that it is legally immaterial whether stranded costs are caused by the Commission's ordering the transmission or the states doing so, and that the determining factor is who has the jurisdiction to make the rates for the service, not who has the jurisdiction to order the service. The opportunity for stranded cost recovery set forth in this Rule is based on the causal link between stranded costs and the availability and use of the Commission-required transmission tariff. It is true that in both the retail-turned-wholesale context and the retail wheeling context there is a limited nexus between stranded costs and Commission-jurisdictional access since, in both situations, the Commission has jurisdiction over the rates, terms and conditions of the transmission service and, therefore, the authority to permit stranded cost recovery through the transmission rates. However, the causal nexus to FERC-jurisdictional transmission and stranded costs in the two contexts (retail vs. retail-turned-wholesale) is different. In the retail wheeling context, there is *no causal nexus* between stranded costs and transmission that has been *ordered by this Commission.* In the retail-turned-wholesale context, in contrast, the opportunity for a utility to seek recovery of stranded costs is grounded on the existence of a *direct causal nexus* between stranded costs and transmission that has been *ordered by this Commission.*

We will reject the rehearing petitions that ask the Commission to act on requests for stranded cost recovery associated with retail wheeling customers not only when the state commission lacks authority, but also when the state commission has authority but either has declined to use it or has only allowed partial recovery. As explained above, our decision to entertain requests to recover stranded costs caused by retail wheeling in a limited circumstance (when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required) is based on our determination to fill any regulatory gap that arises in association with interstate transmission.

We will reject TX Com's request that the Commission clarify that section 35.26(d) (dealing with recovery of retail stranded costs), which refers only to public utilities, should also refer to transmitting utilities. The Commission's decision to act as a limited backstop in the case of stranded costs associated with retail wheeling customers is based on our jurisdiction under sections 205 and 206 of the FPA over the rates, terms, and conditions of retail transmission in interstate commerce. As a result, our ability to allow the recovery of such costs through a surcharge on a section 205 unbundled transmission rate is necessarily limited to public utilities.[721]

Rehearing Requests Opposing Commission Treatment of Stranded Costs Associated With Retail Wheeling Customers in Holding Company Intra-System Agreement Cases

A number of entities oppose the Commission's proposal to address on a case-by-case basis whether jurisdictional intra-system agreements may need to be amended in order to prevent inappropriate cost-shifting that could occur if one state disallows stranded cost recovery associated with retail wheeling customers. IN Com objects that the problem is not the actions of one state or another, but rather the terms of the intra-system agreement.

AR Com objects that Order No. 888 is factually in error because a state's treatment of retail stranded costs under the Entergy System Agreement cannot shift costs to other jurisdictions.[722] It submits that whenever retail load changes, whether due to retail wheeling or any other factor, responsibility ratios under Entergy's reserve equalization schedule, MSS–1, will change and costs will shift irrespective of the regulator's treatment of retail stranded costs. AR Com says that MSS–1 reveals no changes in calculations due to retail treatment of stranded costs or any other retail ratemaking; only ''excess'' capacity costs of intermediate gas- and oil-fired plant are ''shifted'' under the Entergy System Agreement. Although the Commission has the authority to amend intra-system agreements when

[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).

wholesale cost allocations have become unjust and unreasonable, AR Com submits that the Commission does not have jurisdiction to reach to the state level and dictate what retail ratepayers should pay to shareholders. AR Com maintains that a FERC-jurisdictional intra-system agreement extends only to sales for resale (transactions among subsidiaries), and that if a holding company believes that an intra-system agreement is unduly discriminatory as a result of a state's disallowance of costs, the holding company can propose to amend it.[723]

AR Com argues that retail stranded costs fall to state jurisdiction regardless of whether the utility is a member of an interstate holding company. AR Com says that because the costs at issue are in retail rate base, any Commission influence over their recovery could occur only through preemption, but preemption of a state disallowance from retail rate base is possible only if there is a ''trapped cost.'' AR Com submits that a disallowance of retail rate base cost cannot result in a trapped cost because there is no inconsistency between two agencies acting within their jurisdiction; the Commission has no jurisdiction to act. AR Com maintains that, unlike the Grand Gulf situation, the Commission has not mandated any Entergy generation costs into retail rate base. It further says that different state decisions regarding recovery of retail costs are not inconsistent decisions; they represent each state applying its law to its facts. According to AR Com, decisions by states leading to less than full recovery could be deemed inconsistent decisions only if there were a federal guarantee of full cost recovery of retail costs, which there is not.

AR Com and MO/KS Coms assert that the Commission's proposal for holding company situations cannot apply to future holding companies, where there is no history of joint planning justifying cost equalization, nor can it apply to future investments. They contend that this would require an assumption that the utility subsidiaries of a registered holding company have planned, and should plan, together rather than separately (*i.e.*, that interaffiliate transactions are always more efficient than nonaffiliate transactions), and that such assumption would be sound only if having the transaction occur between affiliates is inherently more efficient than having the transaction occur between an affiliate and a nonaffiliate.

Commission Conclusion

The comments raised for the most part are either premature or reflect a misunderstanding of the Commission's decision. Contrary to AR Com's argument, the Commission in Order No. 888 in no way asserted jurisdiction over state determinations of stranded costs associated with retail wheeling customers. We agree with AR Com that our jurisdiction extends only to sales for resale (and transmission in interstate commerce) and that a holding company can seek to amend an intra-system agreement if it believes the agreement is unduly discriminatory as a result of a state's disallowance of costs. However, a holding company also may seek to amend an agreement *before* any potential disallowances can occur, to keep cost-shifting from occurring. The fact is that intra-system agreements which involve wholesale sales among affiliate companies in different states could, through operation of their reserve equalization formulas, result in customers in one or more states having to indirectly bear stranded costs that are disallowed in another state, and the Commission has a responsibility to prevent inappropriate cost-shifting. Such determinations can be made only on a case-by-case basis. Again, as we stated in Order No. 888, we encourage affected state commissions to propose mutually agreeable solutions to this potential problem.

8. Evidentiary Demonstration Necessary—Reasonable Expectation Standard

In Order No. 888, the Commission concluded that a utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. We stated that whether a utility had a reasonable expectation of continuing to serve a customer, and for how long, will be determined on a case-by-case basis, and will depend on all of the facts and circumstances. We also determined that the existence of a notice provision in a contract would create a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the specified period. We said that whether or not a contract contains an ''evergreen'' or other automatic renewal provision will be a factor to be considered in determining whether the presumption of no reasonable expectation is rebutted in a particular case.[724]

We also said that we would apply the reasonable expectation standard to retail-turned-wholesale customers. We explained that, before the Commission will permit a utility to recover stranded costs, the utility must demonstrate that it incurred such costs based on a reasonable expectation that the retail-turned-wholesale customer would continue to receive bundled retail service. Whether the state law awards exclusive service territories and imposes a mandatory obligation to serve would be among the factors to be considered in determining whether the reasonable expectation test is met in a particular case.[725]

We noted that Order No. 888 does not address who will bear the stranded costs caused by a departing generation customer if the Commission finds that the utility had no reasonable expectation of continuing to serve that customer. We indicated that we anticipate that, in such a case, a public utility will seek in subsequent requirements rate cases to have the costs reallocated among the remaining customers on its system. However, we stated that we were not prejudging that issue in the Rule.[726]

Rehearing Requests Opposing or Seeking Modification of the Reasonable Expectation Standard

APPA challenges the reasonable expectation standard as being too vague. It submits that the Commission has provided no guidance concerning application of the reasonable expectation standard, other than to state that it would decide the issue on a case-by-case basis. APPA objects that public utilities can exploit the uncertainty created by this standard, which will lead to costly and time-consuming litigation. IL Com supports replacing the reasonable expectation standard with a statutory, regulatory, contractual standard.

Several entities contend that there is no basis to conclude that the reasonable expectation test could ever be met. VT DPS and Valero submit that, since 1973, utilities have known that a refusal to wheel power could subject them to antitrust liability. They say that Order No. 888 ignores the breadth of NRC

[723] 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.

licensing conditions. LEPA similarly argues that the reasonable expectation standard could not be met where NRC license conditions required an explicit wheeling commitment and prohibited the utility from including in the wheeling cost any amount attributable to the loss of customers due to the wheeling. It objects that delaying a decision on stranded cost recovery in such cases holds the threat of possible stranded cost charges over the heads of bulk power purchasers and thereby chills their ability to seek competitive sellers.

TAPS asserts that there should be an irrefutable presumption that no stranded costs are due from customers with pre-existing transmission rights, including customers who were the beneficiaries of NRC license conditions.[727] TAPS submits that there can be no legitimate ''reasonable expectation'' that such customers would continue to purchase power if the price was higher than the market price.

Occidental Chemical asks the Commission to clarify that a utility could have had no reasonable expectation of recovering stranded costs from customers who, prior to the issuance of the NOPR, had the opportunity to switch to an alternative electric supplier or had the option of self-generating, obtaining on-site third-party generation, or municipalizing. Occidental Chemical further argues that it defies commercial expectations to allow a utility to argue that if a contract is silent on the issue of renewal, the obligation to purchase does not expire with the termination of the contract. It submits that the Commission has not shown that it has the authority to force customers to extend purchase agreements against their will in violation of accepted commercial practice.

A number of entities submit that the Commission erred in failing to treat a notice of termination provision as conclusive evidence that the utility had no reasonable expectation of continued service.[728] Several object that the Commission has failed to explain why the presence of a notice provision does not conclusively demonstrate the lack of a reasonable expectation and *ipso facto* terminate the obligation of the customer to purchase the product.[729] APPA objects that the Commission provided no evidence that it considered comments supporting making the presumption conclusive and that it found legally sufficient reasons to reject them.

PA Munis objects that the rebuttable presumption represents an unjustified departure from the Commission's traditional policy of enforcing the express terms of notice provisions without any inquiry into the reasonable expectations of the party, provided that the agreements were negotiated in good faith and approved by the Commission.[730] PA Munis contends that wholesale requirements customers negotiated notice provisions with the knowledge that the Commission would enforce the notice provisions according to their terms, including the specific length of the term. [731] PA Munis argues that it is arbitrary and capricious to provide utilities an opportunity to seek to amend these contracts.

Several entities submit that the rebuttable presumption invites litigation and promotes uncertainty for customers.[732] APPA objects that the Commission has failed to establish the showing that it would require to overcome the presumption.

Referring to the Commission's discussion of evergreen provisions, Central Montana EC argues that it is wrong to infer from the existence of an automatic renewal provision that the parties intended that the contract might run longer than its initial term. Central Montana EC asserts that the presence of an evergreen provision infers simply that the parties agreed upon a mechanism to avoid the renegotiation of a power supply contract if, at the conclusion of its initial term, the parties were satisfied with the contract. It maintains that the parties' obligations are defined by the term and termination provisions of wholesale power contracts, and that the presence of a mechanism to avoid contract renegotiation does not alter those termination rights.

Commission Conclusion

We will reject the requests for rehearing of our decision to adopt a reasonable expectation standard to be applied on a case-by-case basis and to treat a notice provision in a contract as a rebuttable, not a conclusive, presumption of no reasonable expectation. Contrary to the claims of some entities, the Commission has explained the basis for its finding that utilities may have had an implicit obligation to serve their wholesale requirements customers and, therefore, that a utility should be given an opportunity to demonstrate that it incurred costs to provide service to a customer and that it had a reasonable expectation that it would continue to serve the customer beyond the contract termination date. The same factors that some petitioners contend establish the absence of a reasonable expectation of continued service may be offered as evidence to be considered in determining whether the reasonable expectation test is met in a particular case.

We believe that our decision to treat a notice of termination provision in a contract as creating a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the period provided for in the notice provision is a reasonable one. It places evidentiary significance on the fact that a contract contains a notice of termination provision. Moreover, while it gives the utility an opportunity, based on the facts and circumstances of a particular case, to rebut the presumption of no reasonable expectation, it firmly places the burden of establishing reasonable expectation on the utility. Although some entities support treating notice provisions as a conclusive presumption of no reasonable expectation, as discussed below, we decline to adopt such an inflexible approach. Nevertheless, as we indicated in Order No. 888, when a utility is seeking a contract amendment to permit stranded cost recovery based on expectations beyond the stated term of the contract, we believe that the utility has a heavy burden in demonstrating that the contract ought to be modified.[733]

Contrary to the position of PA Munis, the rebuttable presumption is fully consistent with the Commission's past treatment of notice provisions. For example, the *Kentucky Utilities Company* case cited by PA Munis supports the proposition that, until a customer *exercises* a notice of

[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.

[729] *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.

[731] 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.

termination provision, the utility is under an implicit obligation to continue to serve and plan for the future needs of the customer.[734] Thus, the presence of a notice of termination provision in a contract (particularly one not yet exercised by the customer), in and of itself, may not necessarily support the conclusion that the utility could never prove that it reasonably expected to continue serving the customer beyond the notice period.[735]

In response to APPA's objection that the Commission has failed to establish the showing that it would require to overcome the presumption, we note that the Commission cannot establish such a showing upfront because whether there is sufficient evidence to rebut the presumption of no reasonable expectation will depend on the facts of each case.

We appreciate the concerns expressed by some entities that the rebuttable presumption may increase the customer's uncertainty by inviting litigation. We have carefully weighed the pros and cons of treating a notice provision as a rebuttable presumption of no reasonable expectation versus the pros and cons of treating it as a conclusive presumption of no reasonable expectation. It is true, as some entities assert, that the rebuttable presumption approach presents the potential for litigation between the parties as to whether, in a particular case, the utility can rebut the presumption. The alternative would be to treat all contracts with notice of termination provisions as conclusive evidence that the utility could have had no reasonable expectation that it would continue to serve the customer beyond the specified notice period. While the latter approach presumably would reduce the number of cases in which the issue of a utility's reasonable expectation would have to be litigated, it would do so only by prohibiting a utility from ever demonstrating that, notwithstanding the existence of a notice provision, based on the facts of a particular case, the utility reasonably expected to continue serving the customer. While we do not prejudge the likelihood of a utility being able to rebut the presumption in a particular case, we believe that it would not be in the public interest for the Commission to absolutely preclude a utility from being able to make such a showing. On this basis, we conclude that treating a notice provision as a rebuttable, rather than a conclusive, presumption that the utility did not have a reasonable expectation of continuing service to the customer is, on balance, the fairer and more equitable approach.

Central Montana EC asserts that it is wrong to infer from the existence of an automatic renewal provision that the parties intended that the contract might run longer than its initial term. However, our statement in Order No. 888 that the existence of an automatic renewal provision will be a factor to be considered in determining whether the presumption of no reasonable expectation is rebutted in a particular case makes no such inference. Whether the utility can rebut the presumption will depend on the facts of each case.

Rehearing Requests Supporting Modification of Evidentiary Standard for Retail Customers

Several entities ask the Commission to consider adopting a rebuttable presumption that utilities had a reasonable expectation of continuing to serve any retail load for which they had a public utility obligation to serve. They submit that the burden should be on the former bundled retail customer to show that the utility's service obligation was not binding and that the utility's expectation of continuing service was unfounded.[736] Florida Power Corp and Utilities For Improved Transition suggest that the only exception to such a rebuttable presumption should be for retail customers that gave notice of termination before the effective date of the Rule. EEI expresses concern that the issue may be wrongly decided on the existence (or lack) of an exclusive franchise. It states that while many states do award franchises delineating exclusive service territories, some do not, even though long-established service arrangements are in place. Puget submits that because there is a duty to serve all retail customers, Order No. 888 should provide for stranded cost recovery from all departing retail customers without application of a reasonable expectation test.

NY Com, on the other hand, opposes application of the reasonable expectation standard to stranded costs associated with retail-turned-wholesale customers. It argues that the reasonable expectation test would ignore prudence, customer impact, financial viability and a series of criteria traditionally analyzed by state regulatory agencies in determining rate treatment of costs incurred with the intention of providing service.

Commission Conclusion

We will deny the requests for rehearing of the Commission's decision to apply the reasonable expectation standard to retail-turned-wholesale and retail wheeling customers on a case-by-case basis without adopting a rebuttable presumption that utilities had a reasonable expectation of continuing to serve any retail load for which they had a public utility obligation to serve. When a utility seeks to recover stranded costs from former bundled retail customers, we think it is appropriate that the utility bear the burden of proving reasonable expectation (instead of requiring the customer to bear the burden of disproving the utility's reasonable expectation). Placing the burden on the utility is consistent with the requirement of sections 205 and 206 of the FPA that a public utility demonstrate the justness and reasonableness of its proposed rates. The same factors that are offered as support for the establishment of a rebuttable presumption of a reasonable expectation (such as the utility's obligation to serve all retail customers) may be offered by the utility as evidence to be considered in determining whether the reasonable expectation test is met in a particular case.

We also will deny NY Com's request that the Commission not apply the reasonable expectation standard to retail-turned-wholesale customers. We believe it is appropriate to require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer as that required in the case of a wholesale requirements customer. Moreover, as discussed in Section IV.J.7 above, the reasonable expectation standard contemplates evidence as to what a utility might reasonably expect to recover under state law, and we will give great weight to a state's view of what might be recoverable.

9. Calculation of Recoverable Stranded Costs

In Order No. 888, the Commission considered various proposals regarding how stranded costs should be calculated and who should pay. With respect to the calculation of stranded costs, the Commission rejected as overly complicated and costly an asset-by-asset

[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.'').

[735] *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.

approach to determine the amount of stranded costs assigned to a departing customer. Instead, the Commission determined that the revenues lost approach was the fairest and most efficient way to make this determination during the transition to a competitive wholesale bulk power market. The Commission adopted the following revenues lost formula for calculating the stranded cost for each departing customer: SCO − (RSE—CMVE)×L. The Commission provided a precise definition for each component of the formula,[737] and made the application of the formula, and collection of the resulting stranded costs, subject to a number of conditions.[738]

RSE Issues

Numerous petitioners oppose the use of present revenues in the stranded cost formula.[739] TDU Systems argues that the revenues lost approach is arbitrary and capricious because its effect exceeds its purpose. Specifically, TDU Systems contends that the revenues lost approach can permit overrecovery because it provides recovery of any difference between pre-Order No. 888 cost-plus rates and post-Order No. 888 competitive rates, regardless of the cause of the difference. TDU Systems cites enhanced utilization and technological improvements as two examples of pre-and post-Order No. 888 rate differences that are not competition related, but for which recovery would be provided. TDU Systems states that instead of using present revenues, RSE should be calculated based on the most current, reliable estimate of future revenues.

Multiple Intervenors argues that the revenues lost method assumes that a utility's costs of operating its plants are *per se* reasonable, yet the New York utilities' current rates include levels of O&M, especially wages and benefits, expenses that may reflect inefficiencies and thus are not stranded costs for which a utility's shareholders should be compensated. Similarly, other petitioners oppose as backward-looking the use of present revenues for what should be a forward-looking remedy, consistent with the other elements in the formula.[740] TDU Systems argues that the use of past revenues is inappropriate in a falling cost environment, and notes that new capacity costs are less than the existing capacity costs embedded in a utility's rate base.

NYSEG states that the Commission should permit a utility to reconcile initial stranded cost charges to actual stranded costs on a periodic basis to account for changes in sales, energy purchases from NUGs, and changes in market price. NYSEG supports development of stranded cost charges based on three-year estimates. Under this approach, a customer would pay locked-in charges for a series of three-year periods. At the end of each period, the stranded cost estimate would be revised for the next three-year period. This process would continue until all stranded costs are recovered.[741] Other petitioners support the use of a projected revenue stream or a true-up mechanism.[742] These petitioners argue that a true-up mechanism is necessary to protect all parties against the inevitable risk of inaccurate forecasts.

ELCON argues that calculating RSE based upon customer usage over the past three years results in an artificially high stranded cost because it fails to take into account that the utility would have had to reduce its prices in the future in response to competition. ELCON states that wholesale customers have a reasonable expectation that utility costs will be lower in the future, and thus that the annual revenues contributed by a customer who remains with the utility would be lower than RSE. ELCON further contends that the revenues lost formula should not guarantee the profits the utility was allowed to receive prior to the issuance of Order No. 888 because such revenues included a risk factor (*e.g.*, plant operating risk, or risk of customer insolvency) that is absent under the direct assignment method of allocating stranded costs. ELCON cites *Town of Norwood* v. FERC[743] as support for its position that the RSE should be reduced to reflect the decreased risk associated with the direct assignment approach.

TDU Systems and NRECA also argue that the Commission should eliminate from RSE the risk component of the return on equity contained in present rates. They argue for this adjustment because the Commission is eliminating the risk associated with non-recovery of plant costs by providing full recovery of stranded costs. NRECA further contends that if the Commission keeps the equity return in the calculation of stranded costs, it should permit a consumer-owned system to include an imputed equity component in its RSE if it needs to recover stranded costs.

APPA argues that the use of present revenues fails to reflect future cost reductions expected from accumulated depreciation, load growth, and declining capital costs. APPA further opposes the use of present revenues because present revenues are the direct product of the monopoly power that the utility exercised over transmission. APPA states that RSE should be calculated based upon the price of wholesale power in a competitive market.

CCEM argues that only fixed costs should be eligible for recovery, and that this amount should exclude any return on investment. CCEM would exclude variable costs from the calculation of stranded costs because allowing recovery of variable charges would encourage the continued operation of facilities that are conceded to be uneconomic. CCEM further contends that the Commission should provide less than full recovery of stranded costs so that the utility has some incentive to mitigate them.

Central Vermont states that where the contract does not commit the customer to a set amount of service, the utility's reasonable expectation of the amount of continuing service will not necessarily be reflected in the revenues of the three previous years. Central Vermont urges the Commission to allow utilities the option of showing that their actual reasonable expectation of continued service differs from historical experience. Central Vermont maintains that any other approach would be less than reasonable, and, in fact, would be arbitrary and capricious.

Numerous petitioners[744] would retain the use of present revenues as the RSE; however, they support a limited exception that would permit a utility to seek recovery of certain future cost increases (primarily nuclear decommissioning costs, back-loaded PURPA contract costs, and other deferred costs) if those costs are not in rates now or are in rates but are being under-recovered at present. These

[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.

[738] 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.

[742] *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.

petitioners argue that the majority of these costs were incurred as a result of various regulatory mandates, with the reasonable expectation of future recovery in rates. As a part of their proposal, Utilities For Improved Transition and EEI (and others) support offsetting such cost increases with any decreases in other costs reflected in present revenues. Utilities For Improved Transition maintains that nuclear decommissioning costs, in particular, should be revisited as they become better defined. Similarly, Nuclear Energy Institute and others request that the Commission allow a utility, on a case-by-case basis, to propose its own recovery mechanism, as nuclear decommissioning costs are significantly different from other future cost increases.

Lastly, TDU Systems and NRECA object to the manner by which the formula deducts average transmission-related revenues (which would be unbundled in the utility's new open access tariff) in the development of RSE. TDU Systems and NRECA contend that the transmission credit, because it is based on the revenues that would be generated under a utility's new wholesale tariff, would not reflect that the cost of transmission has been declining.

Commission Conclusion

In Order No. 888, the Commission stated that the use of ''present'' annual revenues as the basis for the stranded cost calculation has numerous advantages over other approaches advocated. The Commission noted that the use of present revenues (1) eliminates disputes over estimates of future revenues, providing certainty to the calculation; and (2) eliminates the need for a detailed listing and litigation of includable costs, relying instead on the presumption that present rates include all just and reasonable costs of providing service. The Commission further noted that the rates that produce present revenues have been approved by regulators, which strongly suggests that the costs included in them are prudent, legitimate and verifiable.

The Commission continues to believe that the use of present revenues as the basis for the stranded cost calculation is superior to other proposed methods. Arguments that the use of present revenues either over-or under-recovers ''true'' costs are not persuasive. Either the customer or the utility may file for a change in rates before the existing contract ends if it believes the existing rate is inappropriate.

In response to petitioners requesting an RSE based on estimates of future revenues for the reasonable expectation period (L), we continue to believe that an approach based on estimates of future revenue streams would engender countless disputes over the RSE component in the formula with little, if any, added accuracy. These would in effect be rate cases that attempt to litigate not what costs were during a test year based on audited accounting data, but what costs will be, based on speculation about future fuel costs, employment levels, capital costs, and so on. In contrast, we believe that the use of present revenues will produce fair results and minimize litigation of RSE. This is appropriate for a transition period cost recovery charge that needs to be settled quickly for market participants to make business decisions about future wholesale sales and purchases. Our approach minimizes transaction costs and provides greater certainty with respect to the RSE term in the formula.

Some have argued that a method that periodically adjusts the departing customer's stranded cost obligation in the future to reflect actual future increases or decreases in a utility's future cost-based rates would produce more accurate results. However, this ''true-up'' approach has several difficulties. First, it assumes that the utility will have wholesale cost-based rates in the future. Many utilities already sell in the wholesale market at market-based rates, and this trend is accelerating. Having a series of ongoing rate cases solely for the purpose of trueing-up a stranded cost calculation would be cumbersome and costly. It would eliminate much of the regulatory cost savings that result from market-based rates. Further, even if ''cost-based'' rates were on file in the future, many such future wholesale rates, as in the past, are likely to result from settlements among the parties. Such settlements are agreements on prices that do not necessarily spell out the cost components of the final agreed-upon rate.

These difficulties aside, the true-up approach would introduce a great deal of ongoing uncertainty about the departing customer's stranded cost obligation. This uncertainty would add unnecessary risk for both the customer and the utility as they consider alternative purchase or sales transactions. Customers would have no way of knowing what their ultimate stranded cost charge would be, and therefore would be unable to evaluate definitively whether changing suppliers would be beneficial. Under a true-up approach, the eventual sum of the customer's SCO and replacement power cost could be more or less than the amount it would have paid had it simply stayed with its host supplier. This possibility could discourage many customers from taking advantage of the open access provided by Order No. 888. We believe that any potential accuracy benefit of a true-up approach is greatly outweighed by the cost, uncertainty, delay, and litigation such an approach would cause.

In summary, we believe that the use of present revenues as the basis for calculating stranded cost appropriately balances precision and efficiency [745] for what is fundamentally a transition period policy.

In response to the other arguments raised, the Commission makes the following findings. We disagree with ELCON that the use of present revenues will result in an artificially high stranded cost because it fails to account for the fact that a utility would have to lower its prices to respond to new competition. ELCON's argument is circular in that much of the new competition to which it refers results from our issuance of Order No. 888. ELCON's approach would undo the goal of providing recovery of stranded costs by eliminating the very difference that the formula is intended to determine. [746] ELCON's argument is rejected accordingly.

In addition, ELCON's reliance on *Town of Norwood* (for the proposition that RSE should be reduced to reflect the reduced operating risk and reduced risk of customer insolvency associated with direct assignment of stranded costs) is misplaced. In *Town of Norwood,* the Commission was faced with a request for recovery of plant costs. The utility made a cost-effective proposal to shut down its single asset, a small nuclear reactor. In that case, the Commission disallowed full return on investment in part because the unit was no longer operating and the utility had no operating risk.

Elimination of the rate of return is inappropriate because, unlike *Town of Norwood,* the departing customer's service is not tied to any particular unit; rather, service is considered to be provided by the entire system. Contrary to ELCON's assertion, operating risk is not reduced because the utility must continue to operate its generating facilities (by reselling the capacity) if it is to recover all its costs. Accordingly,

[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.

there is not a reduced operating risk as argued by ELCON.

With respect to ELCON's customer insolvency argument, this risk is also present under the direct assignment approach. Because Order No. 888 permits a customer to pay its stranded cost obligation over a number of years, during this period the customer could become insolvent, thereby leaving the utility with uncollected stranded costs.[747]

Also, unlike *Town of Norwood*, the utility is presently collecting rates that compensate for traditional utility risks, but do not include the risk of open access. Further, eliminating the rate of return would engender considerable complication, speculation and expense as the Commission would have to determine an appropriate rate of return that included some risks (*e.g.*, customer bankruptcy) but not others (*e.g.*, 211 request or use of the open access tariff). Thus, eliminating the rate of return (or a portion thereof) is inappropriate.

Accordingly, ELCON's arguments that the revenue stream should be reduced to reflect lower risk associated with direct assignment is rejected. Instead, we continue to believe that the transmission provider is entitled to recover all the costs, including return on equity, that it incurred based on a reasonable expectation of having to serve the departing customer. All these costs would have been recoverable absent the action taken in Order No. 888.[748]

The Commission also rejects NRECA's proposal to include an imputed equity component in the RSE when calculating stranded costs for a consumer-owned system. Simply put, if a cost is not stranded, or if a cost is not really a cost, recovery should not be granted.

The Commission rejects APPA's contention that it is inappropriate to use present revenues as the RSE because those revenues are the direct product of the monopoly power that the utility exercised over transmission. The Commission believes that the use of present revenues is one of the strengths of the formula in that the rates that produce present revenues have been approved by regulators as just and reasonable, which strongly suggests that the costs included in them have been shown to be prudent, legitimate and verifiable.

In response to CCEM's argument that only fixed costs should be eligible for recovery (because the inclusion of variable costs in the RSE will encourage the continued operation of facilities that are conceded to be uneconomic), we agree. The Commission notes that condition 1, ''Cap on SCO'' [749] limits the recovery of stranded costs to fixed costs. Accordingly, the formula, as designed, addresses CCEM's concern.

We note that Central Vermont supports its opposition to the use of present revenues differently from other petitioners, who argue (in effect) that the price component of RSE is flawed.[750] Central Vermont, on the other hand, is concerned that the quantity component of present revenues may not reflect the quantity that would have been taken during L. It states that the Commission should permit the utility to show that it had a reasonable expectation of continued customer service that is not based on the customer's previous three years of power consumption. The Commission does not believe that this is appropriate. Central Vermont's approach would introduce forecasting controversy, litigation cost, and uncertainty which are similar to the disputes about cost discussed above. For example, a utility might argue that the customer was expected to consume more than it has in the last three years, based presumably on such factors as expected economic development, changing demographics, appliance saturation rates, and even changes in climate. Conversely, the departing customer might argue that it would have increased electricity conservation efforts, used more natural gas, relied more on self-generation, and so on, if open access had not been made available by Order No. 888. The Commission has stated above why it favors the use of present revenues, for both price and quantity combined, and these reasons apply regardless of whether the argument is directed toward the price or quantity component of present revenues.

Finally, TDU Systems' and NRECA's argument regarding the transmission revenue credit component of RSE is made on the same basis as their argument that the revenue stream should be calculated on a forward-looking basis. For the reasons discussed above, we reject this argument also.

Therefore, after consideration of the arguments on rehearing, and reconsideration of our policy rationale supporting the use of present revenues, we continue to support the use of present revenues, without true-ups or adders, as the basis for the stranded cost formula. We find that the use of present revenues fairly and efficiently balances the competing interests of the affected parties.

CMVE Issues

Petitioners raised a number of CMVE related issues. We take them up in the following two categories.

Present Value Issues

EEI agrees with the Commission that stranded costs should be calculated on a present value basis. EEI states that with respect to RSE, the formula appears to be stated on a present value basis, although it believes that the language could be strengthened to read: ''*the present value of* average annual revenues from the departing customer over the three years prior * * *'' (new text *emphasized*).

However, EEI maintains that the rule fails to define CMVE clearly on a present value basis. Therefore, EEI suggests that the Commission clarify the definition as follows: ''Option 1—the utility's estimate *of the net present value of* the average annual revenues * * * or Option 2—*the net present value of* the average annual cost to the customer of replacement capacity and associated energy * * *'' (new text *underlined*). EEI states that this clarification could also be applied to the ''Cap on SCO,'' to put it on a par with the other definitions in terms of the time value component.

TDU Systems and NRECA also express concerns regarding the calculation of SCO on a present value basis. Specifically, they state that the formula contains no component, factor, or other mechanism to indicate how such present value is to be determined. They also state that no discount rate is specified, and that the calculation should be synchronized with the customer's chosen payment option. Central Vermont maintains that the Commission should make it clear that a utility is entitled to recovery of both

[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.

stranded costs and the time value of those costs from the date on which they were experienced through the date of their recovery.

Commission Conclusion

We believe that EEI misinterprets our intent with the three-year average annual revenues for RSE. EEI is proposing to increase the revenues of three years ago to current dollars, the revenues of two years ago to current dollars (and so on) before finding the three-year average. The Commission clarifies that our use of the term ''present value'' does not require such an adjustment. If the utility thought its rates on file did not adequately reflect rising costs, it should have filed for a rate increase. If it did file for and receive a rate increase, the formula does not use a three-year average, but rather revenue based on the new rate.[751] It would be inappropriate to adjust the three years of revenue used to calculate RSE to a current dollar value if these rates have been in effect for three years without change. It is assumed that all costs, including inflationary and deflationary changes in the underlying costs, have been recovered. We do not have any time lag between the provision of service and the recovery of the costs of providing that service. Accordingly, EEI's proposed present value adjustment is neither necessary nor appropriate.

With respect to EEI's concern that CMVE is not determined on a present value basis, we clarify that it should be calculated on a present value basis. Both the revenues that would have been collected if the customer had remained on the system and the revenues the utility expects to collect by selling the power must be stated on a present value basis so that the difference, RSE–CMVE, is at present value.[752] The ''Cap on SCO'' must also be stated on a present value basis.

In response to TDU Systems, NRECA and Central Vermont, we clarify that a utility is entitled to recovery of stranded costs and the time-value of the revenues that would have been recovered.[753] However, we decline to specify the discount rate or the number of periods to be used in the calculation. Although establishing a uniform discount rate would serve to minimize disputes over the calculation, we prefer to give the parties some flexibility on the use of a discount rate. Similarly, we do not prescribe the number of periods to be used in the present value calculation as this also should be determined on a case-by-case basis due to differences in ''L'' and billing payment cycles for each departing customer.

CMVE Option 2 Issues

In Order No. 888, the Commission allows the departing customer to set CMVE equal to the average annual revenues it would pay to its alternative supplier. This option is referred to as CMVE Option 2.

SoCal Edison and Central Vermont argue that CMVE Option 2 should be eliminated because it will be administratively difficult to monitor and enforce. In their view, Option 2 will allow customers the opportunity to ''game'' the system, which will increase the utility's and the Commission's administrative costs and place the utility at risk for less than full recovery of stranded costs. In addition, SoCal Edison maintains that it will be difficult to reflect in the calculation of stranded costs any non-price benefits a customer may receive under the contract. SoCal Edison further maintains that there is a possibility that additional bargains may have been struck outside of the agreement between the new supplier and the departing customer. These bargains may have the effect of increasing the price of the alternative power, but the terms of the bargains would not be known to the utility to use in adjusting CMVE. As a result, the customer's contract price may not accurately reflect the utility's CMVE, resulting in an inaccurate estimate of stranded cost responsibility.

EEI has requested that the Commission clarify that the conditions placed on CMVE Option 2 were intended to prevent the customer from unfairly avoiding its full stranded cost obligation (*i.e.*, prevent gaming of the stranded cost calculation). EEI also states that the Commission should give the utility an opportunity to challenge the validity of the replacement contract's price, terms and conditions on a case-by-case basis or give the utility the right of first refusal to provide power to the customer under the replacement contract's price, terms and conditions. Carolina P&L requests that the Commission require the departing customer to make a compliance filing containing information regarding the replacement contract. Centerior maintains that in order to guard against the customer overpaying for replacement capacity (thereby lowering its SCO), the Commission should use the revenues received by the host utility in the resale of the power to determine the CMVE.

NRECA and TDU Systems maintain that the formula fails to address how the CMVE component will be adjusted when the customer's contractual commitment for replacement capacity is for a period shorter than L.

Commission Conclusion

The comments filed in response to our Open Access NOPR maintained overwhelmingly that determining accurately the competitive market value of the released capacity and energy is a difficult and subjective task. Therefore, we did not prescribe a CMVE by formula as we did for RSE. Instead, we provide options for determining it. Our requirement for the utility to estimate it is CMVE Option 1. However, the customer may contend that the utility will underestimate CMVE under this option so as to increase the customer's stranded cost obligation. In response to these concerns, the Commission adopted CMVE Option 2 because ''[t]he customer will test the market and choose the best deal available. Hence, the price the customer pays its alternative supplier is arguably a more accurate measure of the competitive market value of the capacity and associated energy not taken from the host utility.'' [754] The Commission also believes that, because of the potential for disputes over the CMVE component of the formula, many utilities and departing customers would appreciate CMVE Option 2 because it would provide them with a simple and reliable method for determining the CMVE.

However, the Commission recognized the potential for gaming on the part of the customer. To address this potential, the Commission placed certain conditions on the use of Option 2. One of these conditions is that the departing customer must demonstrate that the replacement service is equivalent to that from the current supplier. This provides the utility with the ability to investigate whether the new service is essentially the same, in terms of contract duration, terms and conditions, as that which it currently provides the customer. Any unresolvable disputes over the value of

[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.

non-price benefits contained in the customer's replacement contract, which is SoCal Edison's concern, can be developed during a stranded cost hearing, and the Commission will decide the disputed issues based on the record provided. SoCal Edison's concern with additional bargains outside the contract, which increase the contract price and lower the customer's SCO, is properly addressed through the discovery process. The utility could ask for a copy of agreements between the new supplier and the departing customer, and the customer would be obligated to provide the requested information.

Although we recognize that there may be difficulties in assuring the ''equivalence'' of the customer's replacement contract, we believe that CMVE Option 2 creates an incentive for the utility to estimate CMVE as accurately as possible (in Option 1), and provides a quick and simple alternative to protracted litigation of the utility's estimate of CMVE. Accordingly, SoCal Edison's and Central Vermont's request for elimination of CMVE Option 2 is rejected. Also, because a utility is permitted to undertake discovery regarding the terms and conditions of the replacement contract, and any contracts or considerations associated with the replacement contract, we do not believe that it is necessary to give the utility the right of first refusal to supply the departing customer under the replacement contract's price, terms and conditions. EEI's ''gaming'' concerns are best addressed through the discovery process in a stranded cost hearing.

Furthermore, we will not require the departing customer to make a compliance filing containing information about its replacement contract, as the utility can obtain this information through discovery if it is needed and relevant, without automatically burdening the Commission with additional filings or requiring the customer to disclose confidential and irrelevant information. A customer must file replacement contract information only if it chooses to assert that the replacement contract price is relevant to the determination of CMVE.[755]

In response to NRECA and TDU Systems, the Commission reiterates that a customer cannot avail itself of CMVE Option 2 if its replacement contract is for a period shorter than L. This restriction is necessary to ensure equivalence of service.

Marketing/Brokering Option Issues

In Order No. 888, the Commission allows the departing customer to market or broker the capacity that it would strand as a result of its decision to purchase power from an alternative supplier. This option is intended to protect a departing customer from a low utility estimate of CMVE, which would result in a higher stranded cost charge to the customer.

ELCON maintains that the option to broker the released power in response to a ''low balling'' of the CMVE by a utility places an unfair burden on the customer by requiring it to engage in brokering.

SoCal Edison and NIMO argue that a customer choosing the marketing option should pay the utility's estimate of the market value of energy, rather than the average system energy costs for the energy it purchases. SoCal Edison and NIMO argue that the use of average system energy costs is inconsistent with the use of estimated market value used to calculate the customer's stranded cost responsibility and will result in an under-recovery of stranded costs. Florida Power Corp is also concerned that the payment provisions of the marketing option could result in under-recovery of stranded costs. Specifically, Florida Power Corp states that permitting customers to purchase the associated energy at average system variable costs is appropriate if the stranded capacity marketed by the customer is slice-of-system and if the energy used is at the same load factor as the average load factor of the utility's remaining requirements customers. If these conditions are not met, Florida Power Corp states that under-recovery or over-recovery of stranded costs could occur. To prevent this, Florida Power Corp would require the customer to reimburse the utility for the marketed energy at the utility's actual hourly average energy costs for the hours in which the energy is resold.

Occidental Chemical requests guidance as to when a stranded cost is ''legitimate'' and how the utility will develop an estimate of the capacity to be released. Occidental Chemical also requests clarification regarding the obligations of a departing customer to the replacement buyer and whether the departing customer can resell the capacity under terms and conditions different from those under which it bought it. Similarly, CCEM requests that the Commission clarify that there can be no conditions attached to the former customer's use of the capacity, except for conditions pertaining to safety and reliability. CCEM also contends that the 60-day limit for finding a buyer under the brokering option is too short and should be eliminated. CCEM states that if the customer pays for the capacity in the stranded cost charge, it should have flexibility in disposing of it.

Commission Conclusion

The Commission disagrees with ELCON that the brokering option places an unfair burden on the departing customer. The Commission believes that the marketing/brokering option is another effective incentive for a utility to make a good faith estimate of CMVE. Furthermore, we note that the marketing/brokering option is just that: an option. A customer is not required to exercise the marketing/brokering option, just as it is not required to exercise CMVE Option 2. Rather, the marketing/brokering option is available to a customer who believes it can reduce its stranded cost obligation through marketing or brokering the released power.[756]

In response to SoCal Edison, NIMO and Florida Power Corp, the Commission believes that permitting a customer to purchase the associated energy under the marketing option at average system variable costs is appropriate in most instances for at least two reasons. First, the capacity being marketed in all or almost all cases would not be associated with a single asset or subset of assets. Instead, a customer who chooses to exercise this option is purchasing a ''slice of the system,'' *i.e.*, a fraction of the production of all assets. Accordingly, our requirement that the customer purchase the associated energy at average system variable costs is consistent with the notion that it is purchasing a slice-of-the-system. Furthermore, we believe that the customer should have the opportunity to purchase the associated energy at the price it currently pays, and for most customers that price is based on average

[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.

system costs. It is not appropriate to require market value pricing of associated energy when the customer's present payments are based on average system variable costs. For SoCal Edison and NIMO, we further clarify that, when the departing customer markets the released power at a market-based rate and pays average system variable cost for the energy component of the price, the difference between the market price of the power and the average system variable cost determines the market value of the released capacity. When we refer to ''purchasing energy at average system variable cost,'' we refer to compensation for the variable cost component of the sale (mostly fuel cost); we are not referring to the total price of the power sale, which would include a fixed cost recovery component.

We agree with the argument of Florida Power Corp. The Commission recognizes that there may be instances where the departing customer does not purchase energy at average system variable costs. We also recognize that the entity to which the departing customer sells the released capacity may have a usage pattern that differs significantly from that of the departing customer. In this circumstance, the utility should be paid actual hourly average energy costs for the hours in which the energy is resold by the departing customer. Parties should address this issue in their marketing agreement.

In addition, we clarify that the departing customer's capacity charge is the utility's CMVE minus average system variable costs as contained in its estimate of RSE.[757] Hence, the capacity charge is the fixed cost that the utility could recover if it sold the power at market value. This approach assumes that the customer choosing the marketing option is buying a slice of the system and buys the energy associated with the released capacity on the same basis as under its contract with the utility.

In response to Occidental Chemical, a stranded cost is legitimate if it meets the criteria established in the Rule. With respect to the obligations of a departing customer to a replacement customer, such obligations will be governed in part by the individual contracts between the parties. However, with respect to Occidental Chemical's question as to whether the departing customer can resell the capacity under terms and conditions different from those under which it bought the capacity, the Commission finds that, at a minimum, the customer is entitled to resell the capacity and energy under the terms and conditions governing its purchase from the utility. However, customers would not be precluded from negotiating different terms and conditions with the utility.

In response to CCEM's concerns, the Commission will not prohibit a utility from attaching conditions to the former customer's use of the system. There may be circumstances (which we have not contemplated) where certain conditions may be necessary, and we do not wish to foreclose such instances at this time. However, we caution utilities against using this to restrict the customer's use of this option. We reiterate our finding in Order No. 888 that the utility should allow the customer to market/broker the released capacity under terms and conditions comparable to a utility resale of the capacity to a third party.

The Commission disagrees with CCEM that the 60-day period for finding a buyer under the brokering option is too short and should be eliminated. The 60-day period protects both customers and utilities in the event that an acceptable buyer for the power cannot be found. It protects the utility from being stuck with the released capacity for an extended period, during which time it can receive only minimal compensation for it.[758] Similarly, the 60-day limit protects the customer by reverting back to the formula if its brokering attempt is unsuccessful. CCEM's argument that the customer who pays for the capacity in the stranded cost charge should have flexibility in disposing of it ignores the fact that under the brokering option (as opposed to the marketing option), the customer does not take title to the released capacity. For these reasons, the Commission continues to believe that a time limit is necessary, and that 60 days is adequate to meet the dual goals described above.

Length of Reasonable Expectation Issues

American Forest & Paper faults the Commission for failing to limit the period of reasonable expectation to a discrete period, such as three to five years. TDU Systems contends that the threat of stranded costs extends well beyond a mere transition period, and therefore, is inconsistent with the Commission's statement that stranded costs are a transition issue. TDU Systems maintains that the period of reasonable expectation should be defined as the shorter of either the term of the terminating contract or the utility's planning horizon as of July 11, 1994. IL Com states that absent a statutory, regulatory or contractual obligation to incur costs or provide service, the length of a utility's expectation to serve a customer beyond its contract expiration should be zero. However, IL Com states that if a statutory or regulatory obligation to serve can be demonstrated by a public utility on a case-by-case basis, extra-contractual recovery may be appropriate but should not exceed three years. IL Com proposes a formula for L that incorporates a three-year cap.

Commission Conclusion

We reiterate that our stranded cost procedure applies to wholesale contracts only if they are entered into on or before July 11, 1994 (and do not contain exit fees or other stranded cost provisions), so that as these contracts end this stranded cost recovery procedure will cease to apply. This fact alone shows that the policy is a transition issue and not a permanent policy for wholesale requirements contracts. Further, it should be remembered that a utility must demonstrate that it had a reasonable expectation of continued service for a time certain (L) before any stranded cost is recognized to exist or recovery permitted. This is not an insignificant demonstration. Moreover, although we decline to establish an outside limit for L, it is likely that the longer the period claimed by the utility, the harder it will be for the utility to demonstrate a reasonable expectation. In any event, to provide recovery of the full stranded cost, it is necessary that the reasonable expectation period not be limited to an arbitrary number, such as three to five years, as suggested by American Forest & Paper.

Regarding the time it takes to complete the transition to a market unaffected by stranded cost considerations, the Commission distinguishes the reasonable expectation period for determining the amount of stranded costs attributable to a departing customer from the period over which the customer pays for stranded costs. For example, a utility may have incurred a cost under the expectation that the customer would remain for another seven years (L). However, the customer could pay that amount

[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.

immediately, over three years, over seven years, or over a longer period. The period of reasonable expectation, L, is unrelated to the repayment period. If all customers were to choose the lump-sum payment option, the transition period to a market completely unaffected by stranded cost recovery would be short.

In response to TDU Systems, we note that its proposal to define the period of reasonable expectation as the shorter of either the term of the terminating contract or the utility's planning horizon as of July 11, 1994 is not foreclosed by our Rule. When faced with a claim for stranded costs, TDU Systems may argue that either of these limit the reasonable expectation period in that instance. However, it would be inappropriate to limit generically the period of reasonable expectation as suggested because the limitation may not fit all circumstances. We reiterate that whether a utility had a reasonable expectation of continued service, and for how long, will be determined on a case-by-case basis, and will depend on the facts and circumstances of each individual case.

With respect to IL Com's argument that absent a statutory, regulatory or contractual obligation to incur costs, the length of a utility's expectation to serve a customer beyond its contract expiration should be zero, the Commission agrees that such obligations are likely to be the principal reasons for a reasonable expectation in most cases, but we would not preclude a utility from introducing other relevant evidence. If a utility can demonstrate that costs were incurred to serve a customer, based on a reasonable expectation of continued service, and if that customer uses the open access provided by Order No. 888 to reach an alternative supplier, leaving the utility with unrecovered costs, the utility should be allowed to make its case for recovery of those costs based on whatever evidence it chooses to offer.

Implementation Issues

SoCal Edison is concerned that, under the framework established in Order No. 888, a customer could request numerous estimates of stranded costs based on different alternative supply scenarios and departure dates, to which the utility would have to respond in a 30-day period. SoCal Edison states that the Commission should reasonably limit the number and types of requests. SoCal Edison maintains that if the number and type of a customer's requests are unduly burdensome or unreasonable in the utility's view, the utility should be permitted to refuse the requests. Under SoCal Edison's approach, the customer would have the right to petition the Commission to demand that such studies be undertaken.

SoCal Edison also argues that the Commission should allow a utility to assess a reasonable charge to cover administrative costs associated with developing the studies required to produce estimates of stranded cost responsibility.

TDU Systems states that the 30-day period allowed for a customer to respond to a utility's notice of alleged stranded costs is too little time to perform an adequate analysis. In addition, TDU Systems and NRECA maintain that a customer should not be bound by its estimate of stranded cost obligation as filed in a petition for declaratory order or a section 205 or 206 proceeding. They contend that certain elements of the formula depend heavily on data in the public utility's possession, and that the Rule, as written, will encourage the customer to present a low-end estimate of stranded cost liability. TDU Systems and NRECA maintain that the Commission should instead require the customer to state its binding estimate at the close of the discovery period when it presumably would be in possession of the data necessary to make a realistic estimate of the stranded cost floor.

PSE&G argues that a utility should be able to begin recovering stranded costs right away, subject to refund pending the outcome of the proceeding, to eliminate any incentive a customer would have to delay proceedings so as to delay payment of stranded costs.

Commission Conclusion

Regarding SoCal Edison's concern about numerous requests for estimates of stranded costs, we do not believe that the number of requests will rise to the level of ''unduly burdensome'' or ''unreasonable'' in most instances. However, if this problem occurs, a utility can petition the Commission for relief, and we will consider each petition on a case-by-case basis.

The Commission does not agree with SoCal Edison that a utility should be permitted a special charge to cover the cost associated with providing a stranded cost estimate. Such costs are likely to be *de minimis.* Given that Order No. 888 provides an opportunity for full recovery of stranded costs, we do not believe it is appropriate for a utility to charge a customer an additional fee for asking whether it can expect a stranded cost claim.

The Commission also disagrees with TDU Systems that the 30-day customer response period is too short. No utility has argued on rehearing that the 30-day utility response to a request for an estimate is too short, and only TDU Systems argues that the 30-day customer response to the utility's estimate is too short. The 30-day period is intended to speed the negotiation process, with the goal of settling stranded costs disputes without Commission involvement. Order No. 888 requires a utility to provide an estimate of stranded cost responsibility within 30 days of the customer's request for an estimate. We do not believe it is unreasonable to require the customer to respond in like time. Accordingly, we will not modify the 30-day response requirement.

Furthermore, the Commission is unpersuaded by TDU Systems' and NRECA's argument that a customer should be bound by its estimate of stranded cost obligation only after the close of the discovery period. Order No. 888 requires the utility to provide detailed support for its stranded cost estimates, and this information should be adequate to allow the customer to develop its own estimate of any stranded cost obligation.

In response to PSE&G, we clarify that recovery of stranded cost claims filed under section 205, 206, or 211/212 will be governed by these sections and the Commission's promulgating regulations thereto.

Net Benefit Issues

EGA and IMPA argue that the revenues lost approach does not capture the net utility benefits that result from open access. EGA states that no stranded costs should be imposed on any one ''lost'' customer if the utility is a ''net winner,'' that is, where the benefits from the new competitive regime outweigh the utility's stranded costs. EGA states that the formula is unclear as to how the revenues lost approach will take into account the following three potentially beneficial effects of competition: (1) an expanded customer base as a result of enhanced transmission access; (2) reductions in the cost of purchased power, which is resold by a utility; and (3) a utility's ability to obtain higher than cost of service rates for electricity. Freedom Energy argues that the potential future benefit should be factored into the revenues lost calculation.

IMPA maintains that a mechanism should be provided for recovery of the benefits of open access, particularly if a utility does not seek stranded cost recovery. IMPA states that it is economically inefficient for consumers of generation and transmission services to pay stranded costs to those suppliers that have higher than average cost generation, while the benefits from increases in asset value are not shared with the consumers or used to pay for other utilities' stranded costs. IMPA further contends that if the customer's departure as a power customer frees up the generating capacity for remarketing through the use of the transmission system, section 212 of the FPA, as modified by the Energy Policy Act, supports recognition of such benefits in the price paid by the customer for its continued usage. Finally, IMPA maintains that if a transmission provider seeks stranded cost recovery for an asset that appears ''high cost'' due to its relative youth, the asset's future lower cost as an older unit must also be included in the calculation; otherwise the departing customer will be denied the long-term average benefit of the generating asset.

Multiple Intervenors contend that there should be consistent treatment of all assets that deviate from fair market value. For example, if a utility is allowed to recover the difference between the book value of an asset and its lower market value, then that amount should be offset by the appreciated value of any assets that have a market value higher than book value. Similarly, ELCON and Freedom Energy are concerned that the revenues lost approach may overcompensate a utility for stranded costs because it fails to account for the fact that uneconomic assets may be offset by the increased economic value of other assets in a deregulated environment.[759] Freedom Energy states that losses may occur in the short run, but in the long run the utility may be better off.

Commission Conclusion

The Commission believes that the suggestion by EGA and others that a long-run comprehensive analysis be undertaken every time a customer departs, in order to determine whether the utility would eventually be a net winner, is unworkable. Identifying the competitive market value for power during the reasonable expectation period (L) is hard enough; EGA would have us also find the market value of the power for an indefinite time after the expectation period ends. Further, attempts to define which benefits are the result of Order No. 888 would, at the very least, be unwieldy and highly subjective. The Commission's approach, on the other hand, is far less subjective and more likely to produce a reasonable result.

With respect to the specific ''potentially'' beneficial effects of competition during the period L, which EGA states should be used to offset stranded costs, the Commission finds these benefits to be questionable at best. However, if these potential benefits occur, the Rule's stranded cost approach accommodates them. For example, our clarification (*infra*) that the formula addresses load growth responds to EGA's first concern that the formula should take into account the expanded customer base that results from open access. EGA's second concern, *i.e.*, that the formula should reflect reductions in the cost of purchased power, is misplaced. If, in a future market-based pricing world, a utility can purchase power at a lower cost, it must either pass this lower cost through to customers in its cost-based rates or sell power at similarly low market-based rates to other customers. In either case, except for possible timing considerations, it is unable to profit by buying low and selling high. If a utility has such a hypothetical benefit before the customer departs, the customer may file a section 206 complaint prior to the termination of the existing contract, so that the resulting rates, reflecting the reduction in the cost of purchased power, could be used to calculate RSE. Lastly, if a utility can sell at market-based rates that are higher than cost-based rates (other than in the speculative long run), it would not qualify to recover stranded costs.

In addition, ELCON's and Freedom Energy's concern that utilities may be overcompensated under the revenues lost approach is based on a study that assumes a fully deregulated environment. There is no basis for this assumption over the next several years. Furthermore, it is highly speculative whether a particular utility will necessarily be better off in future markets as the study predicts. This is especially so because Freedom Energy's argument that future benefits should be used to offset stranded costs appears to assume a short reasonable expectation period, L. We do not find merit in Freedom Energy's suggestion that events beyond the reasonable expectation period should be factored into the stranded cost calculation.

The Commission also believes that IMPA's benefit reallocation proposal is inappropriate and unworkable. It would require a utility not requesting stranded cost recovery to share with its wholesale customers any future benefits that would accrue to it as a result of Order No. 888. Customers have purchased power from utilities at cost-based rates that have been found to be just and reasonable by this Commission. Such purchases in no way convey an ownership interest in the facilities used to provide service. The rationale for stranded cost recovery, *i.e.*, payment for investments made to serve a customer under the utility's reasonable expectation of continuing to serve, cannot be converted into what would be in effect an ownership interest with the right to receive a share of profits from future sales. Moreover, IMPA's argument assumes that utilities whose assets have a book value less than market value will be able to charge market-based rates for their capacity. This assumption is unrealistic for many utilities, and therefore cannot be relied upon as basis for a generic policy. However, even if all utilities could charge market-based rates, economic efficiency would argue strongly against such utility payments to departing customers. Specifically, there would be little or no incentive for an efficient, low cost utility to seek the best deal in the power market if the profits must be credited back to its former customers, or other utilities' customers, as IMPA suggests. Therefore, while IMPA's symmetry argument (*i.e.*, customers must pay stranded costs so equity requires utilities to pay customers any benefits that result from open access) may have surface appeal, it would serve to undo the goal of Order No. 888—that is, to promote competition and economic efficiency in bulk power markets. The Commission considered carefully the issue of symmetry in Order No. 888 and provided the appropriate utility-customer symmetry: a utility is entitled to make the case that it expected the customer to remain a customer longer than the term of the contract and the customer is entitled to make the case that the term of an existing contract should be shortened.

We also reject IMPA's argument that section 212 of the FPA requires recognition in transmission rates of any generation benefits that accrue to a utility as a result of Order No. 888. Section 212 requires the Commission to consider all costs incurred by the transmission provider in providing the service, ''including taking into account any benefits to the transmission system of providing the transmission service.'' [760] We do not interpret this to refer to the resale of a utility's generation freed-up as a result of Order No. 888.

IMPA's argument that if a transmission provider seeks stranded cost recovery for an asset that appears

[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).

''high cost'' due to its relative youth, the asset's projected future lower (depreciated) cost as an older unit must also be included in the calculation, improperly focusses on an individual asset. As we explained above, the revenues lost approach is not an asset-by-asset approach, but an approach that looks at a utility's current rates which are based on all the utility's assets, including typically a mix of facilities of various ages.

Lastly, the revenues lost approach automatically includes an offset of the type described by Multiple Intervenors, ELCON and Freedom Energy. The revenue stream is based on present rates, which are based on the net book value of all of the underlying assets used to provide the service. If present rates include some assets that have a market value that exceeds net book value (for example, plants that are almost fully depreciated), the formula automatically captures the described offset because the revenue stream is based on the lower book value of the utility's assets rather than their higher market value.

Miscellaneous Formula Issues

Rehearing Requests

American Forest & Paper argues that the definition of wholesale stranded costs in section 35.26(b)(1) is overly inclusive; rather than using a gross measure of stranded costs, it believes the regulations should adopt a net measure that accounts for a utility redeploying its assets in a competitive market at market price. American Forest & Paper also maintains that the formula fails to reward efficient utilities or those that already have borne the pain of restructuring. On the contrary, it argues that the Commission's definition artificially and unjustifiably improves the competitive position of the inefficient utilities. American Forest & Paper further contends that the formula fails to allocate the risk of non-mitigation to utilities, the entities that are in the best position to mitigate such costs, but rather places the risk on customers by requiring customers to challenge the utility's CMVE.

Commission Conclusion

In response to American Forest & Paper, we note that the definition of wholesale stranded cost in section 35.26(b)(1) should not be looked at in isolation. Although that definition does not specifically mention the subtraction of the competitive market value of the released power from RSE, the revenues lost formula, which is set forth in section 35.26(c)(2)(iii), does. The formula explicitly provides that a customer's stranded cost obligation is to be calculated by subtracting the estimated competitive market value (of the released power) from the revenue stream estimate.

In response to the argument that the formula fails to reward the efficient utility that has already borne the pain of restructuring, we note that our intention in providing stranded cost recovery was not to review or reward utility business decisions that preceded this Rule. Our decision was, at bottom, based on equity for a utility that chooses to make a case to regulators for recovery of costs stranded by transmission access. Furthermore, we disagree that the definition of stranded costs artificially and unjustifiably improves the competitive position of an inefficient utility. Instead, the Commission believes that to deny stranded cost recovery would violate the pre-existing regulatory compact and would unjustifiably place certain utilities with stranded costs at a financial disadvantage.

With respect to American Forest & Paper's concern about mitigation risk, the Commission requires the utility to mitigate, or reduce, its stranded cost by reselling the released capacity at a price as high as the market allows. In addition, Order No. 888 contains several other incentives (*e.g.*, the marketing/brokering option) to protect the departing customer from paying an excessive stranded cost charge. These incentives serve to mitigate stranded costs. Regarding the customer's ''requirement'' to challenge the utility's CMVE, we view this as the customer's right to challenge the utility's stranded cost estimate, which is like its right to challenge a cost item in any rate case.

Rehearing Requests

NRECA and TDU Systems maintain that the formula fails to account for any savings or reductions in fuel costs attributable to a customer's departure. NRECA and TDU Systems contend that the utility's fuel costs will decrease equivalent to the incremental fuel costs associated with the energy not taken. They maintain that if the customer's associated revenues are based on average fuel cost energy charges, stranded costs should be offset by the reduction in average system fuel costs directly related to the incremental fuel costs savings. They argue that any stranded cost recovery mechanism should properly reflect such offsetting savings.

Commission Conclusion

The Commission disagrees with NRECA and TDU Systems that the formula fails to account for any savings or reductions in fuel costs attributable to a departing customer. The formula automatically accounts for fuel costs by assuming that the utility will be reselling the same capacity and energy to another buyer, presumably at a lower price. The lower price can be viewed as contributing less to capital cost and purchased power cost recovery, but containing the same fuel cost component. Under this approach, any decrease in fuel cost caused by no longer serving the departing customer is offset by the increased fuel cost of serving the new customer. Hence, there is no fuel costs savings to reflect.

Rehearing Requests—Divestiture

CCEM continues to support divestiture of generating assets as a precondition to a utility's authority to recover stranded costs. CCEM maintains that divestiture is the only way to obtain an accurate determination of CMVE on a net asset basis.

Commission Conclusion

The Commission disagrees that divestiture is the only way to obtain an accurate measure of CMVE and we continue to believe that mandatory asset divestiture does not need to be a requirement for stranded cost recovery. However, the Rule (Section IV.J.10) states that we are willing to consider case-specific proposals for dealing with stranded costs in the context of any voluntary restructuring proceeding instituted by an individual utility.

Rehearing Requests—Load Growth and Excess Capacity

TDU Systems and NRECA argue that the formula fails to take into account the effect of load growth on the recovering utility's revenues. They maintain that if the recovering utility is able to sell the released capacity to new or existing customers, the rationale for stranded cost recovery would be eliminated. Similarly, Arkansas Cities argues that the formula is an imperfect indicator of a utility's stranded costs because it does not explicitly take into account the role played by the utility's having (or not having) excess capacity. PA Munis maintains that as a prerequisite to stranded cost recovery, a utility should be required to prove that the customer's use of open access transmission actually resulted (or could result) in excess capacity on its system.[761]

[761] *See also* Wisconsin Municipals.

Commission Conclusion

We clarify that our stranded cost policy does take into account the effects of load growth and excess capacity. The formula is used to calculate the value of stranded costs only if the Commission determines that the utility has proved it has legitimate, prudent, and verifiable stranded costs. For example, it must pass our reasonable expectation test before the formula applies. However, costs may be stranded only if they are not fully recovered from another customer; that is, the released capacity may be either left unsold or resold at a price below full embedded cost.

The resale may be either to a new third-party customer or to remaining native load. If the released capacity is resold to a third-party customer at full embedded cost-based rates, then no costs would be stranded and the formula would not have to be used. Released capacity would also be considered ''resold'' if its cost is subsequently (and without delay) included in the rate base of the utility's retail and wholesale native load. It may be included if it is needed, in the judgment of the appropriate state or federal regulatory body, for native load growth plus reliability reserve. In this case the cost is not stranded if it is fully recovered in the cost-based rates paid by native load. If the full embedded cost rate is paid by the new purchaser for the capacity released by the departing customer, the parties may argue either that there is no stranded cost or that the formula produces a stranded cost obligation of zero because CMVE equals the embedded-cost rate that the utility charges its wholesale and retail native load customers; hence RSE equals CMVE.

In response to Arkansas Cities, if the released capacity was included in the Commission-approved cost-based rates paid by the departing customer, we presume that such capacity is not ''excess'' capacity. The departing customer's rate (which produces annual revenues, RSE) for the released capacity includes capacity that regulators have approved as needed to meet the needs of requirements customers, including capacity needed for reliability reserve. The only excess capacity issue is whether the released capacity becomes ''excess'' because of the customer's departure, that is, whether the departure strands costs because the utility cannot find a buyer for the capacity. If the released capacity is ''excess'' capacity that is excluded from subsequent native load rates because it is not needed for native load, its cost may be eligible for stranded cost recovery under the formula. Thus, contrary to the arguments made by TDU Systems, NRECA, Arkansas Cities, Pa Munis and others, the revenues lost formula does take load growth and excess capacity into account appropriately in determining the departing customer's stranded cost obligation. For this reason, we reject the arguments made by commenters that the formula is flawed.

Rehearing Requests—Tax Treatment of Nuclear Decommissioning Costs

EEI and Nuclear Energy Institute request clarification that the Commission did not intend Order No. 888 to change the IRS's tax treatment of nuclear decommissioning costs. To be tax deductible, nuclear decommissioning costs must be part of a utility's regulated cost of service. EEI and Nuclear Energy Institute seek clarification that costs included in a utility's stranded cost calculation continue to be considered by the Commission as included in the utility's cost of service.

Commission Conclusion

The requested clarification is granted. We clarify that costs included in a utility's stranded cost calculation continue to be considered by the Commission as included in the utility's cost of service.

Rehearing Requests—Application of Formula to Stranded Costs Associated With Retail-Turned-Wholesale Customers and Retail Wheeling Customers

OH Com, MO Com and KS Com maintain that the Commission's formula is inappropriate for calculating stranded costs associated with retail wheeling customers and/or retail-turned wholesale customers. They contend that the formula would be impractical to administer and would produce inaccurate results given the enormity of the calculations and assumptions involved. Suffolk County argues that the formula is flawed for retail-related stranded costs because the Commission cannot guarantee any retail rates into the future because it has no basis for even speculating about how retail rates may be changed by subsequent state action.

Commission Conclusion

With respect to stranded costs caused by retail wheeling, the Commission determined in Order No. 888 that the formula was inappropriate, and that if the Commission had to determine stranded costs associated with retail wheeling it would do so on a case-by-case basis. [762] However, the formula does work for stranded costs associated with retail-turned-wholesale customers because the newly formed municipal utility would have the resources to engage in marketing or brokering and would have a marketable product. This stands in contrast to individual retail customers, most of whom are unlikely to have the resources to engage in marketing or brokering and would have very small amounts of energy for sale. Although the calculations necessary to estimate stranded costs associated with retail-turned-wholesale customers are somewhat more involved than stranded costs associated with wholesale contracts, they are not impossible or overly burdensome. Accordingly, we affirm our finding in Order No. 888 that the formula is appropriate in the retail-turned-wholesale context.

Rehearing Requests

Allegheny Power states that stranded cost recovery should not be permitted if a utility recovers large amounts through exit fees, then uses the freed capacity to make sales in the market at anything over variable costs. Allegheny Power argues that a utility with nuclear generation, which has a low variable cost, can dump power on the market because its fixed costs are subsidized by stranded cost recovery. Allegheny Power requests that the Commission recognize that this distortion of the competitive market should not be facilitated by stranded cost recovery.

Commission Conclusion

Allegheny Power's concern that a utility recovering stranded costs will use those revenues to subsidize sales in the market at anything above variable costs is misplaced. In the power market, power pricing decisions are based on whether the utility can recover its variable cost, plus earn some contribution to capital costs. Stranded cost revenues are not relevant. This fact is demonstrated by considering the situation where no stranded cost revenues are provided to a utility with nuclear generation as described by Allegheny Power. The utility, in pricing power for off-system sales, would still face the same choice, *i.e.*, make the sale and earn some minimal contribution to capital, or forego the sale and earn nothing. The Commission's decision to provide recovery of stranded costs does not change the economics involved in utility power pricing decisions, and does not lead to the type of market distortion that concerns Allegheny Power.

[762] FERC Stats. & Regs. at 31,840; *mimeo* at 598.

Rehearing Requests

SBA asserts that determining the proper amount of stranded cost recovery is an integral step in the deregulation process.[763] It expresses concern that the revenues lost formula can be abused through the manipulation of the necessary financial statements of the parties and that such abuse could be harmful to small businesses. SBA requests that the Commission solicit its input, as well as the input of the small business community and small business organizations, when determining whether the proposed stranded cost recovery amount in a particular case is fundamentally fair in terms of maintaining a viable environment for small businesses.

Commission Conclusion

In response to SBA's request, we note that SBA, or any interested small business organization, has the opportunity to provide input to the Commission in a particular stranded cost proceeding by filing a motion to intervene in that proceeding.[764]

10. Stranded Costs in the Context of Voluntary Restructuring

No rehearing requests were filed on this issue. The Commission reaffirms that we are willing to consider case-specific proposals for dealing with stranded costs in the context of any restructuring proceedings that may be instituted by individual utilities.[765]

11. Accounting Treatment for Stranded Costs

No rehearing requests were filed on this issue. The Commission reaffirms Order No. 888's treatment of this issue.[766]

12. Definitions, Application, and Summary

In Order No. 888, we defined ''wholesale stranded cost'' in section 35.26(b)(1) as follows:

(1) *Wholesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) 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. [767]

We rejected requests by commenters in this proceeding to expand the definition to include the situation where a wholesale requirements customer or a retail-turned-wholesale customer ceases to purchase power from the utility without using the transmission services of that utility.[768] We explained that any costs that the utility might incur as a result of the loss of the requirements customer in this scenario would be outside the scope of this Rule. We noted that the premise of this Rule is that, where a customer uses Commission-mandated transmission access of its former power supplier to obtain power from a new generation supplier, the customer must pay the costs that were incurred to provide service to the customer under the prior regulatory regime. We indicated that if a customer leaves its utility supplier by exercising power supply options (such as access to another utility's transmission system or self-generation) that do not rely on access to the former seller's transmission, there is no nexus to the new open access rules.[769]

We also decided to retain the requirement that stranded costs be ''legitimate, prudent and verifiable,'' rejecting requests by some commenters to eliminate the term ''prudent'' from the definition of stranded costs.[770] We explained that a determination that a utility had a reasonable expectation of continuing to serve a customer would not, in all circumstances, mean that costs incurred by the utility were prudent. We said that prudence of costs, depending upon the facts in a specific case, may include different things: *e.g.*, prudence in operation and maintenance of a plant; prudence in continuing to own a plant when cheaper alternatives become available; prudence in entering into purchased power contracts, or continuing such contracts when buy-outs or buy-downs of the contracts would result in savings. We concluded that the Commission cannot make a blanket assumption that all claimed stranded costs will have been prudently incurred, but we clarified that we do not intend to relitigate the prudence of costs previously recovered.

Rehearing Requests—Definitions of ''Wholesale Stranded Cost'' and ''Wholesale Requirements Contract''

As discussed in Sections IV.J.1 and IV.J.6, *supra*, a number of entities ask the Commission to expand the scope of stranded cost recovery allowed under the Rule to include ''bypass'' situations (*i.e.*, situations in which a departing customer does not use its former supplier's transmission system to reach another supplier). Coalition for Economic Competition asks the Commission to revise the definition of ''wholesale stranded cost'' to accomplish that result. It notes, for example, that the reference in the definition to ''newly created wholesale power sales customer'' creates an ambiguity and may provide a loophole to evade stranded costs through municipal annexation.

El Paso expresses concern that a retail-turned-wholesale customer could attempt to avoid its stranded cost responsibility simply by having its outside power supplier be the ''wholesale transmission customer'' (*i.e.*, the entity that formally requests transmission service from the transmitting utility). El Paso asks the Commission to clarify that a retail-turned-wholesale customer is responsible to the transmitting utility for stranded costs regardless of whether it or its outside power supplier is the ''transmission customer'' of the transmitting utility. El Paso asks the Commission to revise section 35.26(c)(1)(vii) (which presently provides for recovery from retail-turned-wholesale customers through section 205–206 or 211–212 wholesale transmission rates) to provide for the recovery of stranded costs directly from retail-turned-wholesale customers (through an exit fee or lump sum payment).

Utilities For Improved Transition asks the Commission to expand the definition to include costs incurred to provide service to ''a wholesale requirements customer that loses retail load because of retail wheeling,

[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] *See* 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.

[769] 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.

municipalization of retail load, the creation of a new customer, or because retail customers have bypassed its system through transmission or distribution taps to other suppliers or by other means.'' [771] Utilities For Improved Transition argues that, in the case of retail wheeling and municipalization, these costs are incurred because of open access tariffs. It further submits that the Commission also should include costs incurred because of taps (interconnections) to other systems to avoid encouraging uneconomic bypass as a way to avoid stranded cost charges.

APPA expresses concern that the definition in section 35.26(b)(4) of ''wholesale requirements contract'' as ''a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements'' could be read as including a bundled sale of capacity regardless of whether the seller undertook to meet the customer's load growth. As a result, APPA submits that the definition could include coordination arrangements. It is APPA's position that the Commission could not, or should not, have intended to allow stranded cost recovery for such contracts. APPA asks the Commission to specify on rehearing that a ''wholesale requirements contract'' is a bundled power and transmission arrangement that includes the obligation to meet some or all of the customer's load growth, and that all other services are coordination arrangements to which the stranded cost recovery rules do not apply.

Commission Conclusion

We will reject the requests for rehearing that ask the Commission to expand the scope of stranded cost recovery allowed under the Rule to include situations in which a wholesale requirements customer (or a retail-turned-wholesale customer) ceases to purchase power from the utility without using the transmission services of that utility. As we explain in Sections IV.J.1 and IV.J.6, *supra,* any costs that the utility might incur as a result of the loss of the customer in these scenarios would be outside the scope of Order No. 888. However, as discussed in Section IV.J.6, we grant rehearing on the municipal annexation issue.

We share El Paso's concern that a retail-turned-wholesale customer should not be able to avoid its stranded cost responsibility simply by having its outside power supplier be the entity that formally requests unbundled transmission service from the utility. As we explain in Section IV.J.6, *supra,* in response to a similar concern expressed by Puget, we have revised the definition of ''wholesale stranded cost'' in section 35.26(b)(1)(ii) to cover this situation. As revised, that section provides that ''[*w]holesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: * * *. (ii) a retail customer that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

We will deny Utilities For Improved Transition's request that the Commission expand the definition to include costs incurred to provide service to ''a wholesale requirements customer that loses retail load because of retail wheeling, municipalization of retail load, the creation of a new customer, or because retail customers have bypassed its system through transmission or distribution taps to other suppliers or by other means.'' Utilities For Improved Transition, in effect, is asking that the Commission allow the recovery of costs that may be stranded due to the loss of an indirect customer and to expand the scope of the ''wholesale stranded costs'' for which Order No. 888 provides an opportunity for recovery. As we discuss in Section IV.J.1, *supra,* the Commission does not believe it is appropriate to expand the scope of the stranded cost recovery opportunity provided under this Rule to include costs that may be stranded due to the loss of an indirect customer (*i.e.,* a customer of a wholesale requirements customer of the utility). The reasonable expectation analysis would apply only to the direct wholesale requirements customer of the utility, not to the indirect customer. A utility may seek to recover stranded costs from a direct wholesale customer (subject to the requirements of the Rule), but it is up to the direct wholesale customer, through its contracts with its customers or through the appropriate regulatory authority, to seek to recover stranded costs from its customers.

In response to APPA's argument that the definition of ''wholesale requirements contract'' in new section 35.26(b)(4) of the Commission's regulations could be read as including coordination arrangements, we clarify that it does not. The opportunity to recover stranded costs applies only to bundled power contracts where the utility can demonstrate that it incurred costs to provide service to a customer based on a reasonable expectation of continuing service to the customer beyond the contract term. Coordination arrangements could not meet the cost incurrence and reasonable expectation prerequisites of Order No. 888, and therefore a customer served under such an arrangement would not be subject to stranded cost charges.

Rehearing Requests—Relitigation of Prudence

A number of entities express concern that, notwithstanding the Commission's stated preference not to relitigate prudence, Order No. 888 leaves the door open for subsequent litigation of prudence issues. Centerior asks the Commission either to remove ''prudent'' from the definition or to clarify that ''prudent'' means all costs found prudently incurred by the state commissions. Centerior asks the Commission not to relitigate prudence in the operation and maintenance of a plant or the prudence of continuing to own a plant when cheaper alternatives become available. Other entities (including EEI, PSE&G, and Nuclear Energy Institute) similarly ask the Commission to clarify that it does not intend to relitigate costs that are already in rates when calculating the revenue stream estimate. Nuclear Energy Institute states that, in the case of nuclear plants, significant prudence proceedings have already been conducted and, by definition, the embedded capital costs included in current rates to customers are prudent.

PSE&G recommends that if costs that form the basis for a utility's claimed stranded costs are already included in filed rates and are no longer subject to refund, those costs should be treated as *per se* prudent. Southern states that if the Commission does not strike the word ''prudent'' from the definition of stranded costs, at a minimum it should modify the Rule to establish a rebuttable presumption of prudence that must be overcome by the departing customer.

PSE&G and Carolina P&L submit that if prudence challenges under the Rule are retained on rehearing, they should be subject to the same standards as any other prudence challenge, namely the ''reasonable person test'' under which prudent costs are those ''which a reasonable utility management * * * would have made, in good faith, under the same circumstances, and at the relevant point in time.'' [772] PSE&G and Carolina P&L ask the Commission to limit the prudence review to the reasonableness of the costs that were incurred to provide wholesale requirements service based on the

[771] Utilities For Improved Transition at 17.

[772] Both note that this is the prudence standard that the Commission applied in Order No. 636.

utility's reasonable expectation of continued service. They ask the Commission to clarify that it will not permit prudence proceedings to devolve into collateral attacks on stranded cost recovery and unfocused debates on the sufficiency of the utility's efforts to adapt to changes in the industry, such as its decisions on staffing reductions and asset write-offs.

Commission Conclusion

In Order No. 888, we specifically stated that we do not intend to relitigate the prudence of costs previously recovered but that we would not preclude parties from raising prudence in stranded cost proceedings. Because we believe that this approach adequately ensures that the prudence of costs previously recovered at this Commission or a state commission will not be relitigated for stranded cost purposes, we will reject the rehearing requests that seek elimination of the term ''prudent'' from the definition of stranded costs.[773] However, we make certain clarifications below in response to the rehearing petitions.

As an initial matter, we clarify that the Commission's determination in Order No. 888, which is reaffirmed here, is the same approach the Commission traditionally has followed regarding prudence matters.[774] Costs are assumed prudent unless a party or the Commission raises a serious doubt as to prudence; then the burden is on the utility to prove that costs were prudently incurred.[775] If costs have previously been recovered in rates (either following an explicit prudence determination or based on an implicit assumption of prudence because no one raised prudence), they *cannot* be relitigated. However, if prudence has not previously been litigated or if certain costs or activities have become imprudent,[776] a party may raise the issue as it pertains to *future* cost recovery.[777] The Commission intends to apply the same prudence standards with regard to future cost recovery, including stranded costs.

We further clarify that we do not intend to relitigate, for purposes of stranded cost determinations involving retail-turned-wholesale customers or unbundled retail customers, the prudence of costs for which rate recovery has been allowed by state commissions. Similarly, in calculating the revenue stream estimate, we do not intend to relitigate the prudence of any costs for which rate recovery has been allowed by this Commission or a state commission.[778]

In response to PSE&G and Carolina P&L, we also clarify that, in cases in which we do entertain stranded cost claims, the standard to be used for reviewing the prudence of a utility's costs is the ''reasonable person'' test that we apply in other contexts.[779] This test gives utility managers ''broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers.'' [780] It asks whether the costs are those ''which a reasonable utility management * * * would have made, in good faith, under the same circumstances, and at the relevant point in time.'' [781] We clarify that we do not intend to permit prudence proceedings to become an opportunity for collateral attacks on stranded cost recovery.

K. Other

1. Information Reporting Requirements for Public Utilities

In the Final Rule, the Commission indicated that it will not now eliminate the public disclosure of allegedly competitively sensitive, proprietary, or otherwise confidential data submitted to the Commission on Form No. 1, as well as on other Commission forms.[782] It explained that the information it collects from public utilities is necessary to carry out its jurisdictional responsibilities and is used, among other things, to evaluate the reasonableness of cost-based rates subject to the Commission's jurisdiction and the operation of power markets.[783] Moreover, the Commission noted its explanation in ConEd:

> [r]eports required to be submitted by Commission rule and necessary for the Commission's jurisdictional activities are considered public information. 18 C.F.R. § 388.106. In addition, the Commission has long required jurisdictional utilities to submit Form 1 data on a form that states on its cover that the Commission does not consider the material to be confidential. [784]

The Commission expressed sensitivity to the lack of symmetry in the generation information we require from traditional public utilities, particularly those that have market-based rate authority, and the generation information required from other public utilities (*e.g.,* public utility marketers) authorized to sell at market-based rates, but explained that the record in the proceeding is insufficiently developed to make and support a well-informed decision requiring a different reporting scheme, particularly given the industry's current rapid pace of change. Also, the Commission indicated that it was not persuaded that the burdens borne by traditional public utilities (primarily annual reports submitted months after-the-fact) are impairing the competitiveness of these utilities so much that we must act hastily now, instead of deferring a decision to a more appropriate proceeding.

However, the Commission stated that it will monitor its reporting requirements to make sure that they are needed, fair to all segments of the industry, and consistent with the workings of a competitive environment.

Rehearing Requests

Allegheny asserts that this proceeding is the proper forum to evaluate the public disclosure of information required from public utilities because it is necessary to avoid disparate treatment of market participants that violates the comparability standard and leads to market distortions. It argues that the Commission should eliminate the requirement to file data on Form No. 1 and other informational filings, or alternatively the Commission should protect the information as proprietary and confidential.

Centerior argues that the Commission should eliminate the public disclosure of the cost-based generation rates and provide for symmetry between the information provided by public utilities

[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).

[775] *Id.* at 61,644; Anaheim Riverside, et al. v. FERC, 669 F.2d 799, 809 (D.C. Cir. 1981).

[776] 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.

[777] *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).

[780] New England Power Company, 31 FERC at 61,084.

[781] *Id.*

[782] FERC Stats. & Regs. at 31,851–52; *mimeo* at 631–32.

[783] *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.

and power marketers by eliminating the reporting requirements.

EEI indicates that it intends to petition the Commission for further action on information reporting requirements in the near future. It adds that it seeks to work with the Commission in streamlining the reporting process and in creating a level playing field.

Commission Conclusion

We are not persuaded that the information reporting requirements for public utilities need to be changed *at this time.* Very simply, it is premature to take such a step at a time when much of the industry is still under cost-based rate regulation for sales of electric energy and when corporate restructuring, including utility mergers, is occurring at a rapid pace. On rehearing, entities have merely reiterated the arguments that we previously addressed in the Final Rule and have presented no evidence that the competitiveness of traditional public utilities is being impaired by their having to submit primarily annual reports that are filed months after the fact. Accordingly, we will continue to require public utilities to submit the information required by our rules and regulations and we will monitor our reporting requirements as the industry environment continues to change.

2. Small Utilities

The Commission noted that it was sympathetic to the array of concerns raised by small public utilities and small transmission customers and explained that the regulations it was adopting include waiver provisions under which public utilities and transmission customers, and non-public utility entities seeking exemption from the reciprocity condition, may file requests for waivers from all or part of the Commission's regulations or for special treatment.[785] However, the Commission explained, it is difficult to imagine any circumstance that would justify waiving the requirements of this Rule for any public utility that is also a control area operator.

The Commission recognized that it might be a financial burden on small public utilities to unbundle generation from transmission, follow standards of conduct that separate transmission personnel from wholesale marketing personnel, and maintain an OASIS. In addition, the Commission explained that for small public utilities that own no generation and buy at wholesale on a radial transmission line from another utility's grid or if their service territory is part of another utility's control area, the small public utility should be permitted to make a showing that it should be exempt from all or some of the Rule.

The Commission further explained that because the possible scenarios under which small entities may seek waivers from the Final Rule are diverse, they are not susceptible to resolution on a generic basis and the Commission will require applications and fact-specific determinations in each instance.

In addition, the Commission indicated that it will apply the same standards to any entity seeking a waiver. The Commission explained that this includes public utilities seeking waiver of some or all of the requirements of the Rule, as well as non-public utilities seeking waiver of the reciprocity provisions contained in the pro forma open access tariff. The Commission concluded that it would not apply the open access reciprocity provision to small non-public utilities that are not control area operators and either do not own or control transmission or have transmission that no one is likely to ask to use. However, the Commission explained that they will have to apply for this waiver and demonstrate that they qualify for the waiver.

Rehearing Requests

APPA asserts that absent a finding that a non-public utility has market power or has exhibited undue discrimination, the non-public utility should be granted a waiver.

Michigan Systems asks that the Commission modify the Rule to provide a blanket waiver for systems that by their nature cannot have market power over transmission and do not have the personnel to separate functions. It also asserts that the Final Rule waiver procedure is cumbersome and time consuming.

Tallahassee asks the Commission to clarify that it will liberally apply its waiver policy to small public utilities even if they run a control area. It asserts that the proper focus of concerns over competition are a utility's size, its ability to manipulate the market, and how it operates its control room.

CAMU asks the Commission to clarify that the small utilities waiver will be generally available to those entities lacking market power because only utilities with market power are capable of subverting the transmission market.

Commission Conclusion

The issues raised with respect to waivers for small utilities are more appropriately addressed in individual fact-specific proceedings. As we explained in the Final Rule,

> [b]ecause the possible scenarios under which small entities may seek waivers from the Final Rule are diverse, they are not susceptible to resolution on a generic basis and we will require applications and fact-specific determinations in each instance. We note here that any waivers that we may grant depend upon the facts presented in each case.[786]

Indeed, we have granted a variety of waiver requests by small utilities since issuance of the Final Rule.[787]

3. Regional Transmission Groups

a. Incentives for RTGs To Form and Resolve Regional Transmission Issues

In the Final Rule, the Commission expressed its continued support for the development of RTGs and encouraged regional tariffs.[788] To further encourage the development of RTGs, the Commission stated that it will accept regional open access transmission tariffs developed by RTGs that are consistent with the objectives of this Rule.

b. Deference To RTGs to Develop Regional Tariffs and Prices

In the Final Rule, the Commission indicated its intent to give deference to the planning, dispute resolution, and decisionmaking processes of an RTG. [789] With respect to pricing proposals submitted by RTGs, the Commission stated that RTGs may be able to develop solutions to such problems as loop flows through innovative flow-based pricing methodologies.

Rehearing Requests

No requests for rehearing addressed this matter.

4. Pacific Northwest

In the Final Rule, the Commission encouraged the filing of regional open access transmission tariffs.[790] It also explained that the Final Rule pro forma tariff contains provisions allowing utilities to modify tariff terms to reflect prevailing regional practices. The Commission concluded that this should permit entities in the Pacific Northwest

[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.

to address unique circumstances that exist in the Pacific Northwest and to incorporate prevailing regional practices (*e.g.*, treatment of hydropower generation in the priority of dispatch) into their open access transmission tariffs.

Rehearing Requests

No requests for rehearing addressed this matter.

5. Power Marketing Agencies

a. Bonneville Power Administration (BPA)

In the Final Rule, the Commission stated that BPA is not a public utility under section 201(e) of the FPA and, thus, is not subject to the requirements of this Rule to put the Final Rule pro forma tariff into effect.[791] However, the Commission indicated three circumstances under which the Commission may review BPA's transmission access and pricing policies.

With respect to stranded costs, the Commission clarified that the Rule addresses only stranded costs recovered by public utilities under the FPA and transmitting utilities (including BPA) that are subject to mandatory transmission requests under FPA section 211. It explained that the Rule does not address stranded cost recovery by BPA under the Northwest Power Act.

Rehearing Requests

BPA asks the Commission to clarify that it did not intend to address stranded cost recovery by BPA under either the Northwest Power Act or section 212(i) of the FPA. If Order No. 888 is intended to govern stranded cost recovery by BPA in the case of Commission-ordered transmission under section 211, BPA asks the Commission for an opportunity to brief the issue on rehearing.

Commission Conclusion

We clarify that our review of stranded cost recovery by BPA would take into account the statutory requirements of the Northwest Power Act and the other authorities under which we regulate BPA (*e.g.*, DOE delegation for interim rate approval) and/or section 212(i), as appropriate.

b. Other Power Marketing Agencies

In the Final Rule, the Commission explained that Federal power marketing agencies (PMAs) are not public utilities as defined under section 201(e) of the FPA and, thus, are not required by this Rule to file non-discriminatory open access transmission tariffs.[792] However, the Commission did state that to the extent a PMA receives open access transmission service from a public utility, it is subject to the reciprocity provisions in the utility's pro forma tariff.[793]

With respect to SEPA's concern that the proposed point-to-point tariff has a one MW minimum scheduling requirement, but many of its customers have loads of less than one MW, the Commission clarified that the Final Rule pro forma tariff will allow SEPA to continue to schedule service for these customers. The Commission also clarified that SEPA, as a seller of power to multiple purchasers inside several control areas, is eligible to receive network service.

Rehearing Requests

Entergy asks the Commission to clarify that SEPA can obtain network service only in the same manner as any other customer and that there was no intent in the Rule to create a special type of network service for SEPA.

Commission Conclusion

We will clarify that for purposes of obtaining network service SEPA is to be treated as any other customer.

6. Tennessee Valley Authority

In the Final Rule, the Commission stated that TVA is not a public utility under section 201(e) of the FPA and, thus, is not required to file a non-discriminatory open access transmission tariff under this Rule.[794] However, the Commission explained, if TVA receives open access transmission service from a public utility, it is subject to the reciprocity provision in the utility's pro forma tariff.[795]

Rehearing Requests

No requests for rehearing addressed this matter.

7. Hydroelectric Power

Non-Firm Transactions

In the Final Rule, the Commission explained that it will permit entities to incorporate prevailing regional practices (*e.g.*, treatment of hydropower generation in the priority of dispatch) into regional open access transmission tariffs.[796] This, the Commission indicated, should permit entities in a region to resolve concerns over the scheduling of non-firm hydropower.

Commission's Licensing Practices

The Commission explained that the issues raised by National Hydropower with respect to the Commission's hydroelectric licensing practices are beyond the scope of this rulemaking. The Commission also noted that these issues were raised in a petition to the Commission to revise hydroelectric licensing procedures, filed on July 10, 1995. That is the proper proceeding, the Commission explained, in which to address the Commission's hydroelectric licensing practices.

Rehearing Requests

No requests for rehearing addressed this matter.

8. Residential Customers

In the Final Rule, the Commission stated that it was convinced that the proposed changes for wholesale markets will benefit residential consumers. [797] Moreover, the Commission explained that the Rule does not require retail transmission access for retail customers of any size and does not require any changes in programs such as assistance to low-income and elderly consumers and weatherization and energy conservation, which are, and will remain, under the jurisdiction of the individual states. The Commission further noted that the Rule contains several safeguards to maintain the ability of states to impose conditions on retail access, such as conditions that help to protect residential customers from becoming the residual payer of stranded costs.

Rehearing Requests

No requests for rehearing addressed this matter.

9. Miscellaneous Issues

Unconstitutional Taking of Property

Union Electric declares that the imposition of an onerous regime of mandates governing what utilities must and must not do with their own property constitutes an unconstitutional taking of their property in violation of the takings clause.

[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.

[793] 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.

[795] 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.

Commission Conclusion

Union Electric has provided no valid legal or factual basis to support its arguments that our final orders result in an unconstitutional taking of property in violation of the takings clause. We have a statutory obligation under the FPA to remedy undue discrimination in the transmission or sale of electric energy subject to our jurisdiction. In Order No. 888, we concluded that unduly discriminatory and anticompetitive practices exist today in the electric industry and that such practices will increase as competitive pressures continue to grow in the industry.[798] Accordingly, we exercised our remedial authority by issuing Order Nos. 888 and 889 to ensure that unduly discriminatory practices can no longer occur.[799]

In exercising our remedial authority, we did not alter the traditional principle that a utility is entitled to a reasonable opportunity to recover its prudently incurred costs.[800] Union Electric has provided no evidence that it will not be adequately compensated for whatever services it may provide on its system following the effectiveness of Order Nos. 888 and 889. To the extent a third party uses Union Electric's transmission system, it must still compensate Union Electric for that usage, as has happened in the past. There simply cannot be an unconstitutional taking of property when public utilities continue to have the right to file for and receive rates that provide them a reasonable opportunity to recover their prudently incurred costs. Indeed, as the Supreme Court has explained, ''[a]ll that is protected against, in a constitutional sense, is that the rates fixed by the Commission be higher than a confiscatory level.'' [801] Union Electric has made no showing that Order Nos. 888 and 889 will result in its rates being set at a confiscatory level. Furthermore, the rate that Union Electric may charge for transmission service is currently before the Commission in Docket No. OA96–50–000 and Union Electric should make arguments regarding the reasonableness of its transmission rate in that proceeding. [802] Moreover, Union Electric is free to propose changes to the rate it charges for transmission from time to time to ensure that it is being fairly compensated for its investment in its transmission system, as well as any expenses it incurs in providing such service.

Section 206 Complaints

Cleveland states that, unfortunately, it has suffered significantly because of denied transmission access and the inefficacy of long-delayed enforcement relief under section 206 of the FPA. Thus, Cleveland states that the Commission must announce its intention to enforce transmission and related obligations and, having made that pronouncement, take whatever steps are necessary to do so.

TAPS states that throughout the Final Rule the Commission points to complaint procedures to redress complaints against transmission providers' open access tariffs and argues that the Commission must clarify that these complaints will receive expedited treatment.

Commission Conclusion

The Commission has a statutory obligation to act if it finds, upon its own motion or upon complaint, that any rate, charges, or classification demanded, observed, charged, or collected by any public utility, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, and to determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed. Moreover, section 206(b) of the FPA requires that whenever the Commission institutes a proceeding under this section it must establish a refund effective date. In carrying out its obligations under section 206 of the FPA, the Commission acts as expeditiously as is possible, given the complexities of the issues at hand, its other workload and its level of staffing. The Commission will continue to work as expeditiously as possible in resolving section 206 proceedings, as well as in resolving all of the other matters that come before it. Given the critical importance of timely, comparable transmission access in fostering competitive wholesale power markets, the Commission intends to vigorously enforce utilities' open access obligations. [803]

We would emphasize that filing complaints with the Commission is not the only avenue that transmission customers (or potential customers) can pursue to raise their concerns. Under the Open Access Transmission Tariff, parties can and should avail themselves of the Dispute Resolution Procedures set forth in section 12 of the pro forma tariff. This section provides that an arbitrator must render a decision and notify the parties within ninety days of appointment.

NRC Remedial Orders

Cleveland asks that the Commission clarify that directives requiring non-discriminatory treatment of transmission customers are not intended to override, but are expected to accommodate, valid remedial orders of the NRC imposed in the form of nuclear license conditions.

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[798] FERC Stats. & Regs. at 31,682–84; *mimeo* at 136–142.

[799] 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.

[801] FPC v. Texaco, 417 U.S. 380, 391–92 (1974); *see also* FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 585 (1942).

[802] 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.

Commission Conclusion

We will deny Cleveland's requested clarification because it is overly broad. However, we do clarify that we view our jurisdiction under the FPA and the NRC's jurisdiction as complementary. In that regard, a utility subject to the Commission's jurisdiction and to the NRC's jurisdiction would have to comply with the orders of both commissions. Moreover, just as the NRC cannot and does not enforce this Commission's orders, it is not within our jurisdiction to enforce orders of the NRC. In the event that an entity believes that it must, but cannot, comply with separate orders issued by this Commission and the NRC, it should present evidence to this Commission and/or the NRC of such a conflict. To the extent necessary and appropriate, we would attempt to resolve any such conflicts subject to our jurisdiction under the FPA.

Retail Customers' Future Access to Transmission Capacity

IL Industrials states that the Commission should fashion safeguards to prevent monopolization of transmission capacity by wholesale customers before retail customers are entitled to engage in direct access. Alternatively, IL Industrials states that the Commission should specify that this issue will be addressed in the CRT NOPR proceeding and that contracts or other arrangements affecting available transmission capacity will be subject to safeguards to protect retail customer transmission access.

Commission Conclusion

This matter is beyond the scope of this proceeding. We have no way of ascertaining the transmission capacity that a retail customer may require in the future should it become entitled to engage in direct access through a state-approved program or voluntary action by its current transmission provider. We cannot require a transmission provider to keep transmission capacity available for all possible transactions that a retail customer may possibly enter into in the future. Just as transmission customers must take the system as it exists at the time of a request, so must future potential transmission customers take the system as it exists at the time of their request.

Transaction Accommodation Arrangements

NCMPA argues that the Commission failed to address the problem of market power arising from a transmission provider's control over transaction accommodation arrangements, which it states are arrangements needed by transmission dependent utilities to accommodate third-party transactions within an existing power supply relationship between the TDU and the transmission provider. NCMPA explains that this problem is most apparent where there is a comprehensive power supply relationship that purports to establish most or all of the TDU's bulk power needs. For example, NCMPA points out that because of Duke Power Company's control over transaction accommodation arrangements, NCMPA has been frustrated in its attempts to pursue beneficial bulk power transactions with parties other than Duke. NCMPA asks that the Commission require transmission providers to provide these arrangements on a comparable basis, state that it will take prompt action to remedy a denial of comparable arrangements, and require that any utility seeking specific permission for any action premised on the mitigation of market power to demonstrate that it has offered comparable transaction accommodation arrangements to any TDU that requires such arrangements.

Commission Conclusion

NCMPA's concerns appear to be related to its existing power supply arrangements, not with new service under the pro forma tariff. These concerns are more appropriately addressed in a case-specific section 206 complaint proceeding before the Commission.

Ohio Valley—Power to Uranium Enrichment Facility

Ohio Valley asks the Commission to clarify that the orders do not apply to Ohio Valley so that Ohio Valley can continue to provide the lowest possible cost, and most reliable, service to the Piketon, Ohio uranium enrichment facility owned by the United States.[804] Otherwise, Ohio Valley argues, compliance could result in increased costs to the United States and to the customers of the utilities participating in providing power to the enrichment facility. Ohio Valley seeks to avoid unnecessary interference with its ability to carry out its obligations under the existing agreements, but is amenable to reasonable and prudent use of its transmission system in accordance with sections 211 and 212.[805]

[804] Ohio Valley states that the facility is now leased by the United States to the United States Enrichment Corporation.

[805] 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).

Commission Conclusion

Ohio Valley's rehearing request is essentially an application for waiver that is not properly addressed in this proceeding. By order issued July 2, 1996, we explained that because of the fact-specific nature of waiver requests the Commission will not address such requests in a generic rulemaking proceeding, but will require entities seeking waiver to submit separate, fact-specific requests that will be docketed in separate OA proceedings.[806] Subsequently, Ohio Valley filed a separate petition for waiver in Docket No. OA96–126–000 that effectively reiterated the arguments made in its rehearing request. The Commission will address Ohio Valley's fact-specific arguments in Docket No. OA96–126–000.

Exchanges

Several entities argue that exchanges should be permitted without a requirement that customers book capacity for each direction the power will flow and parties should not each have to pay the full reservation charge.[807] Because point-to-point customers can change receipt points without payment of additional charges, they argue that the same logic applies to exchanges.

Commission Conclusion

An exchange between two utilities has traditionally been viewed as two separate transactions (two one-way services) from the transmitting utility's planning and reservation perspective and has been priced as two separate services. Consistent with this approach, the pro forma tariff only allows changes to points of receipt and delivery for point-to-point service on a *non-firm* basis at no extra charge. Any changes to points of receipt and delivery on a *firm* basis must be submitted to the Commission as new applications. However, we note that comparability is achieved if the transmission provider charges itself and its transmission customers for point-to-point service on a consistent basis, whether that be separately for both directions or on a bidirectional basis.

Various Rate Matters

VT DPS and Valero argue that rates ''should be based on a definition and quantification of a core of transmission function lines and substations for use in wholesale wheeling rather than on the basis of a rolled-in rate for the entire

[806] Order Clarifying Order Nos. 888 and 889 Compliance Matters, 76 FERC ¶ 61,009 (1996).

[807] *E.g.*, VT DPS, Valero, APPA.

transmission network.'' VT DPS states that ''[i]n order to insure against cross subsidization, the tariffs should provide for the imposition of a Local Transmission System Access Charge to recover the costs of the facilities used to provide service to customers in this category.'' (VT DPS at 23–24; Valero at 8–10).

American Forest & Paper argues that

> the Commission's proposal includes as part of the transmission revenue requirement amounts attributable to the utility's use of its own transmission system to effectuate off-system sales and revenues received from transmission customers taking service under existing contracts and tariffs but not under the new transmission tariffs. By failing to subtract such revenues from the revenue requirement used to determine rates for services rendered under the new tariffs, the utility effectively recovers these amounts twice: once from its off-system sales and transmission customers not taking service under the new tariffs and a second time from its customers taking service under the proposed new tariffs.''[808]

American Forest & Paper asserts that to eliminate this double-recovery, the Commission should adopt PacifiCorp's proposal in Docket No. ER95–1240. American Forest & Paper further declares that the Commission must demonstrate that the charges imposed on customers of network wheeling service are commensurate with the benefits that they receive.

Commission Conclusion

We are not prepared to mandate in a generic proceeding such as this that all transmission rates must be established by function or that a specific pricing methodology should be used. Our rate policy, as set forth in the Transmission Pricing Policy Statement, is to encourage flexible and innovative rate approaches by the electric industry. Mandating a single methodology for the entire industry would certainly defeat that goal. While the Commission welcomes new and innovative proposals, we will not impose a generic change in this proceeding. As always, utilities are free to propose the use of a functional pricing method in their compliance filings or in any section 205 filing it may submit to the Commission.

Federal Government Contract Clauses

ConEd asserts that the Commission must modify the pro forma tariff to include certain Federal government required anti-discrimination clauses. According to ConEd, these clauses require that all of Con Edison's transmission providers agree to be bound by certain provisions of the federal subcontractor regulations. ConEd suggests that the ''Commission state that Con Edison and similarly-situated utilities be permitted to comply with the federal subcontracting requirements by inserting such clauses in their service agreements for transmission services.'' (ConEd at 17–18).

Commission Conclusion

The Commission disagrees with ConEd's assertion that the Commission must modify the pro forma tariff to include certain Federal government anti-discrimination clauses. The Commission does not dispute that certain parties must comply with provisions of the federal subcontractor regulations for particular transactions that may involve the provision of transmission service. However, we do not agree that these provisions must be incorporated into the pro forma tariff. The contracting obligation raised by ConEd is independent of the pro forma tariff and more appropriately addressed in a separate contract between the parties to the purchase or the service agreements for transmission services. The Commission notes that this is apparently how the issue has been handled in the past by ConEd because its tariffs previously filed with the Commission (pre-NOPR) did not include such anti-discrimination clauses.

V. Environmental Statement

Summary

The Commission prepared an environmental impact statement (EIS) to evaluate the environmental consequences that could result from adopting the Rule. We did so largely in response to the claims of several commenters who charge that the Rule will have significant adverse environmental effects. As described in Order No. 888:

> Although a number of issues were raised, by far the most prominent concern arises from the theory that competitive market conditions created by the rule will provide an advantage to power suppliers who produce power from coal-fired facilities that are not subject to stringent controls on nitrogen oxides (NO_X) emissions. Under this theory, these facilities, located primarily in the Midwest and South, will, as a result of the rule, generate more power and emit more NO_X, which will contribute to ozone formation. The ozone could add to pollution both in those regions and more significantly in the Northeast, to which area such pollutants could be transported. Those who propound this theory argue that it is the responsibility of the Commission, using its authority under the Federal Power Act, to effect environmental controls that will mitigate what they predict will be significant increases in NO_X emissions associated with this rule.[809]

The EIS recognizes that the electric industry will contribute to air emissions regardless of whether the Rule is adopted. The purpose of the EIS is to analyze to what extent the Rule is likely to affect those emissions.

Many variables can influence the impacts of the Rule and the EIS uses a modeling framework that incorporates a range of assumptions about these variables. The most significant variable is likely to be the future prices of the two primary fuels used to generate electricity—coal and natural gas. Government and industry price forecasts were used to construct two alternative fuel price assumptions: (1) that the price of natural gas will increase relative to the price of coal; and (2) that the relative price of coal and natural gas will remain constant. These assumptions form the basis for two base cases that project the environmental impacts of developments in the electric industry without the Rule. The EIS then makes assumptions about the effects of the Rule to create three scenarios that project a range of possible results. It compares the environmental impacts projected in the scenarios with those projected in the base cases to determine the effect of the Rule.[810] The analysis set forth in the EIS demonstrates that the Rule will not in any significant respect affect overall trends in NO_X emissions.

Subsequent to the issuance of Order No. 888, the Environmental Protection Agency (EPA) conducted a review of the Commission's FEIS in which EPA employed alternative assumptions for a number of model inputs. In doing so, EPA stressed that ''[n]aturally there can be differences among reasonable analysts concerning the assumptions used in such an analysis'' and that ''EPA believes the assumptions used by the FERC and those used by EPA both lie within the reasonable range.''[811] EPA has concluded that the Rule is unlikely to have any significant adverse environmental impact in the immediate

[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.

future, and that implementation of the Rule should go forward without delay. In reaching these conclusions, EPA concurred that the Commission conducted an adequate NEPA analysis of the environmental impacts of the Rule under a range of possible scenarios. EPA also agreed that the Commission made a reasonable choice of models with which to conduct the analysis and, as noted above, made assumptions for various factors input into the model that lie within the range of reasonable assumptions.

EPA also concurred with the Commission that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states pursuant to the Clean Air Act. EPA committed to use its Clean Air Act authority to support successful completion of this program, and stated that it will establish a NO_X cap-and-trade program through Federal Implementation Plans if some states are unwilling or unable to act in a timely manner.

In a letter dated May 13, 1996, the EPA Administrator referred Order No. 888 to CEQ.[812] In doing so, EPA suggests that if the Ozone Transport Assessment Group (OTAG) and Clean Air Act processes fail to produce the necessary pollution limitations in a timely manner, EPA will call upon all other interested federal agencies to assist in solving the problem. EPA would ask the Commission to contribute by examining, through a Notice of Inquiry, possible strategies for mitigating NO_X emissions increases associated with the Rule.

The Commission subsequently responded by issuing an order stating that if EPA concludes that the OTAG process has not succeeded in meeting its objectives in a timely manner, the Commission would initiate a Notice of Inquiry to further examine what mitigation might be permissible and appropriate under the Federal Power Act. Such an inquiry would solicit public comment on how to assess appropriately the air pollution impacts attributable to the Rule, suitable ways in which to address such impacts, if any, and the scope of the Commission's authority to address such impacts. The Commission also stated that, under the extraordinary circumstances in which EPA would undertake a Federal Implementation Plan, the Commission would agree to initiate contemporaneously a rulemaking to propose possible mitigation that could be undertaken by the Commission under the FPA. Such a rulemaking would be undertaken on the basis of the Notice of Inquiry discussed above and would be appropriate only if environmental harm attributable to the Rule that warranted mitigation is demonstrated.[813] On June 14, 1996, CEQ concluded that the Commission's order was fully responsive to EPA's concerns and requests and that the referral process and corresponding responses to the referral from the Commission and other agencies have successfully resolved the disagreements between EPA and the Commission.[814]

As discussed below, EPA is currently taking steps to implement a comprehensive NO_X emissions control program to ensure that emissions reductions are achieved to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. OTAG is continuing to work in conjunction with EPA on this issue and intends to complete its process in the near future.

Rehearing is sought on eight categories of issues relating to the Commission's analysis of environmental issues: selection of the appropriate no-action alternative; challenges to modeling assumptions; need for mitigation; emissions standards disparity; the short-term consequences of the Rule; cost benefit analysis; socioeconomic impacts; and compliance with the Coastal Zone Management Act. For the reasons discussed below, rehearing is denied.

A. The Appropriate No-Action Alternative

The FEIS discusses several alternatives, including the alternative of instituting open access pursuant to section 211 of the FPA. The FEIS states in this regard that:

> Actions taken pursuant to section 211 and pursuant to sections 203 and 205 in merger and market-rate cases, respectively, represent a case-by-case approach to establishing open access. Absent action on the proposed rule, the Commission would continue using these authorities to require utilities to file open access tariffs and provide case-specific service, as necessary or appropriate. In addition, sections 205 and 206 charge the Commission with ensuring that purely voluntary transmission tariffs are not unduly discriminatory. Thus, if the proposed rule were not adopted, the Commission would continue to require that voluntary tariffs be upgraded to offer the Commission's current standards for non-discriminatory open access transmission services. The result of continuing the Commission's policies without the proposed rule is that the Commission would effectuate a more open transmission grid, but in a patchwork manner and at a slower pace.
>
> The case-by-case approach to achieving open access currently in use is slower and more costly, and thereby less desirable, than the generic approach set forth in the proposed rule. Thus, the no-action alternative is not a reasonable alternative to the proposed rule.[815]

Rehearing Requests

The PA Com contends that the FEIS does not adequately consider the alternative of instituting open access pursuant to section 211 of the FPA. It states that section 211 provides a means for wholesale power sellers and buyers to obtain transmission services necessary to compete in, or to reach competitive markets, and that the FEIS ignores the steady, if slow, progression to open access taking place under section 211.

Commission Conclusion

The FEIS notes that there are significant reasons for implementing open access through a rulemaking rather than the case-by-case approach of section 211. In the absence of a Commission rulemaking, the development of open access pursuant to section 211 would occur as potential transmission users file requests for such services and the Commission approves them as appropriate. Such proceedings are likely to be contested by competitors and the Commission would decide each application individually. Given the number of potential transmission users who are likely to file requests for such services, it is conceivable that this approach may require the Commission to decide a large number of such applications. [816] Thus, the case-by-case approach is likely to be much slower and more costly to implement than action by rule.

Case-by-case implementation of open access is also more likely to result in patchwork development as the policy evolves over time. It is important to develop uniform national standards to facilitate the move to open access. This approach adds certainty and facilitates development and implementation of open access in a way that would be difficult to achieve on a case-by-case basis. The development of national

[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).

[814] 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.

standards is best done through a mechanism whereby all interested parties can participate in shaping the policy through notice and comment rulemaking. The piecemeal implementation of open access on a case-by-case basis over time, no matter how carefully conducted, is likely to result in inconsistencies and difficulty in application. Given the national nature of the electric grid and the developing open access market, case-by-case implementation is not practical nor desirable and will limit the anticipated benefits of open access.

The PA Com does not specify how the Commission fails to adequately consider the alternative of instituting open access pursuant to section 211. It is insufficient for a party to complain that an analysis is inadequate without providing specific support for its claim. As the court noted in *Northside Sanitary Landfill, Inc.* v. *Thomas*, 849 F.2d 1516, 1519–20 (D.C. Cir. 1988), *cert. denied*, 489 U.S. 1078 (1989):

> In *Vermont Yankee Nuclear Power Corp.* v. *Natural Resources Defense Council, Inc.*, 435 U.S. 519, 98 S.Ct. 1197, 55 L.Ed.2d 460 (1978), then-Justice Rehnquist expressed the unanimous opinion of seven members of the Supreme Court that a party * * * has the burden of clarifying its position for the [agency]. Even though the [agency] has the statutory obligation to consider fully significant comments, ''it is still incumbent upon intervenors who wish to participate * * * to structure their participation so that it is meaningful, so that it alerts the agency to the intervenors' position and contentions.'' 435 U.S. at 553, 98 S.Ct. at 1216. Justice Rehnquist, then quoted with approval Judge Leventhal's remarks in *Portland Cement, id.*, and concluded that administrative proceedings should not be a game or a forum to engage in unjustified obstructionism by making cryptic and obscure references to matters that ''ought to be'' considered and then, after failing to do more to bring the matter to the agency's attention, seeking to have that agency determination vacated on the ground that the agency failed to consider matters forcefully presented.''

Id., at 533–54, 98 S.Ct. at 1217.

We also note that the PA Com's quarrel does not appear to be with the Commission's analysis of the section 211 alternative in any event, but rather with the underlying policy decision to implement open access through a rulemaking rather than more slowly on a case-by-case basis.

The Administrative Procedure Act authorizes agencies to establish policies by rulemaking or on a case-by-case basis. Here, the Commission has properly exercised its discretion to establish open access by rulemaking rather than in individual proceedings. The PA Com does not contest this authority or the Commission's exercise of it. Rather, its complaint goes to the underlying policy choices guiding that decision. Disagreement with an agency's policy choice is not a proper basis for a NEPA-based challenge to agency action. As the Circuit Court of Appeals for the District of Columbia (D.C. Circuit) stated in *Foundation on Economic Trends* v. *Lyng*, 817 F.2d 882, 886 (D.C. Cir. 1987) (footnote omitted) (brackets in original):

> NEPA was not intended to resolve fundamental policy disputes. As the Supreme Court recently admonished, ''[t]he political process, and not NEPA, provides the appropriate forum in which to air policy disagreements.'' *Metropolitan Edison Co.* v. *People Against Nuclear Energy*, 460 U.S. 766, 777, 103 S.Ct. 1556, 1563, 75 L.Ed.2d 534 (1983) (citation omitted). A policy disagreement, at bottom, is the gravamen of appellants' complaint. In our view, ''[t]ime and resources are simply too limited for us to believe that Congress intended to extend NEPA as far as [appellant would take] it.'' *Id.* at 776, 103 S.Ct. at 1562. [817]]

Contrary to the PA Com's assertion, and regardless of the basis for that assertion, the discussion of the section 211 alternative in the FEIS satisfies the requirements of NEPA. The Supreme Court has stated that ''[t]o make an impact statement something more than an exercise in frivolous boilerplate the concept of alternatives must be bounded by some notion of feasibility.'' [818] ''Central to evaluating practicable alternatives is the determination of a project's purpose.'' [819] ''The range of alternatives that must be considered in the EIS need not extend beyond those reasonably related to the purposes of the project.'' [820] The purpose of the Rule is to implement open access in order to remedy undue discrimination and to do so on a timely basis and in a uniform manner; the Commission has determined that case-by-case implementation of open access will not satisfy that purpose.

[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).

[819] National Wildlife Federation v. Whistler, 27 F.3d 1341, 1345 (8th Cir. 1994).

[820] 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.

The PA Com has proffered no reasons why the examination in the FEIS of the section 211 alternative is insufficient. We conclude that the FEIS adequately considers the alternative of instituting open access pursuant to section 211. Rehearing on this issue is denied.

B. Challenges to Modeling Assumptions

Several rehearing requests challenge the modeling assumptions used in the FEIS. These challenges are raised in support of the claim that the Commission's analysis understates the environmental impacts of the Rule. The most fundamental challenge is the PA Com's claim that computer modeling is insufficient to examine the impacts of the Rule. The PA Com and Joint Commenters suggest that the model fails to use the appropriate base case. Questions are also raised regarding specific assumptions used in the model.

In discussing these issues below, we note that although EPA raised many similar points with respect to the Commission's modeling approach in comments on the DEIS, EPA ultimately concluded that ''the FERC has conducted an adequate analysis under the National Environmental Policy Act of the environmental impacts of the open access rule under a range of possible scenarios'' and that ''[t]he FERC made a reasonable choice of models (CEUM) and made assumptions for various factors input into the model that lie within the range of reasonable assumptions.'' EPA also notes that the Commission performed the specific additional analyses that were requested in comments on the draft EIS.

As EPA points out, ''[n]aturally, there can be differences among reasonable analysts concerning the assumptions used in such an analysis.'' EPA then reiterates that it believes that assumptions used by the Commission ''lie within the reasonable range.'' It concludes that ''the FEIS provides a credible basis for understanding the possible environmental impacts of the open access rule.''

1. Appropriate Base Case

Selection of the appropriate base case was contested in the DEIS on grounds similar to those presented here. Certain commenters argued that the Commission should compare the impacts of the Rule to a no-action alternative that assumes that the Commission abandons all open access policies, not just the Rule. Some commenters went even further, suggesting that the Commission compare emission levels projected to result from the Rule against a frozen efficiency case in which other major factors—factors that would increase industry efficiency independent of the Rule—do not occur. Such factors include adoption of pro-competitive state polices and actions by utilities to undertake mutually beneficial voluntary transactions that do not require the use of open access tariffs mandated under the Rule. Commenters who advocated either a different no-action alternative or the frozen efficiency case posited that studies using those assumptions would show that the Rule will cause significantly greater NO_X emissions than those shown in the DEIS. We concluded in Order No. 888 that:

[S]taff has selected the appropriate ''no-action'' alternative. An alternative that requires the Commission to reverse all its other open access policies is simply not a ''no-action'' alternative. To the contrary, it would require decisive action running counter to the direction from the Congress in the Energy Policy Act and the needs of the marketplace and electricity consumers.

However, to ensure that the effects of the rule were analyzed fully, the FEIS did study a reference case based on the ''frozen efficiency'' case * * * Although, as described below, we believe this case to be highly unlikely, the results show that, even under this scenario, the impacts of the rule are not great and do not vary significantly from those projected by staff under the other assumptions. [821]]

Rehearing Requests

Pennsylvania PUC. The PA Com asserts that the Commission did not compare emissions levels associated with the Rule against the appropriate base case. It claims that the Commission should have used continued case-by-case evolution of open access and increased wholesale competition under FPA sections 211 and 212 as the base case instead of generic, simultaneous, nationwide open access as mandated by Order No. 888. Put differently, the PA Com claims that the appropriate base case is the evolution of competition and open access without the intervention of Order No. 888. The PA Com concludes that by using the improper base case the FEIS ignores evidence of significant NO_X increases resulting from the Rule, which affects the ability of Pennsylvania to meet the mandates of the Clean Air Act.

Joint Commenters. The Joint Commenters maintain that the FEIS uses an inappropriate no-action alternative as a basis for analysis. [822] The gist of its argument is that the Commission must acknowledge the policy initiative of which it contends Order No. 888 is only one part. It claims that the Commission ignores the fact that, whether competition is pursued through Order No. 888 or on a case-by-case basis, implementation of open access is a major programmatic policy choice the environmental impacts of which must be addressed. It contends that by using case-by-case implementation as the no-action alternative, the Commission effectively defines away most of the impacts of the Rule.

In short, the Joint Commenters claim that by defining the no-action alternative as implementation of the open access program over a longer period of time through case-by-case action, the Commission did not fully examine the potential impacts of Order No. 888. It states that if the effects of Order No. 888 are defined to include only those that result from the timing difference between implementation of open access through case-by-case decisions and open access pursuant to a generic rule, it is virtually a foregone conclusion that most of the potentially adverse environmental effects of the Commission's open access policies will not be identified.

The Joint Commenters concur that the frozen efficiency case analyzed in the FEIS is a proper starting place for an acceptable NEPA review. It faults the discussion of the frozen efficiency case, however, as failing to provide important information needed to allow parties to evaluate the analysis. The Joint Commenters complain that the analysis does not include the model outputs which demonstrate the most severe environmental effects; this, they claim, makes it impossible to verify the results or analyze the factors contributing to the effects shown.

The Joint Commenters state that in addition to omitting the modeling outputs for the most environmentally relevant cases, the FEIS does not contain air quality modeling of the scenarios that show the greatest emissions increases. It claims that the Urban Airshed Model (UAM–V) examines only the incremental impacts of the Competition-Favors-Coal Scenario as compared with the High-Price-Differential Base Case, the same analysis presented in the DEIS. The Joint Commenters stress that EPA in its comments on the DEIS noted that the results shown for this case (an emissions decrease) is illogical and should be explained. It states that without modeling the emissions changes associated with the Competition-Favors-Coal Scenario over the frozen efficiency base case, the FEIS provides no indication of the seriousness of the environmental harm from potential emissions increases caused by FERC's initiatives. The Joint Commenters also claim that the expanded transmission analysis used in the FEIS is unduly conservative.

Commission Conclusion

The Commission continues to believe that the base cases and scenarios used in the DEIS are most appropriate for studying the effects of the Rule. Nonetheless, to ensure that the effects of the Rule were analyzed fully, the FEIS also examined a frozen efficiency case that uses a combination of assumptions most likely to show significant increases in emissions.

We did this despite our belief that it is inaccurate to attribute all efficiency improvements in the industry to Order No. 888 or even to federal actions of all kinds. In fact, as noted in the FEIS, the frozen efficiency case is far more extreme in its assumptions than would be reasonable for a no-further-Commission-action case because it presumes that industry and state regulators also cease all changes toward a more competitive industry. However, the frozen efficiency case is useful as a sensitivity analysis because it reflects an extreme bound on any separate no-further-Commission-action case. [823] *A fortiori* the impact actually to be expected from the Rule must be less than that determined using the frozen efficiency case.

We believe that the frozen efficiency analysis is highly implausible because its represents a world in which: (1) the Commission reverses current pro-competitive transmission policies (inconsistent with congressional mandates under EPAct); (2) states cease to adopt programs to improve industry efficiency; and (3) electric companies cease to improve operation or to enter into mutually beneficial transactions.

The Joint Commenters agree that the frozen efficiency analysis constitutes a valid NEPA review. That issue, therefore, is not in dispute. It objects that the FEIS does not include the model outputs for the sensitivity cases which demonstrate the most severe environmental effects, and that it is therefore impossible to verify the results or analyze the factors contributing to the effects shown.

The Joint Commenters' assertion is incorrect. Appendix K of the FEIS sets forth tables demonstrating the results of

[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.

the model runs for the sensitivity analysis. These tables provide adequate documentation to analyze and verify the conclusions reached in the FEIS. We note also that the Joint Commenters have not requested specific model outputs that it claims are lacking. The Commission will make available information used in the study that Joint Commenters or anyone else identifies as not being provided.

As to the claim raised by the PA Com, it appears to be mistaken regarding the base case actually used in the FEIS. Contrary to what the PA Com states, the base cases do include continuing case-by-case actions under section 211 and the Commission's open access policy.

2. Challenge to the Use of Computer Modeling

The Commission's intent to use computer modeling in the identification and evaluation of the impacts of the Rule has been clear since the Commission decided to prepare an EIS. The DEIS and FEIS explain the computer modeling techniques used in the analysis in great detail.

For example, the DEIS and FEIS explain that the Coal and Electric Utilities Model (CEUM) was selected for the analysis because it is the best tested, most widely used national-level model available. [824] CEUM is a forecasting model that incorporates virtually all coal and electric utility market activities—ranging from mining, transportation, and blending of coal to power plant and system dispatching, transmission, and new capacity construction. It also examines the impact of changes in factors such as plant availabilities, heat rates, planning reserve margins, and transmission costs. CEUM has been used extensively by, among others, EPA and DOE.

CEUM models the contiguous United States as 45 separate demand regions. It possesses a supply component which models key coal supply regions and coal transportation networks in great detail. It also incorporates constraints on long-term coal supplies, power plant emission limitations, national emission caps (*e.g.*, acid rain requirements of Title IV of the Clean Air Act Amendments of 1990), coal transportation capacity, electric transmission capacity, and power plant construction plans.

The DEIS and FEIS explain that to analyze the Rule, assumptions as to factors such as electricity demand growth rates, oil and gas prices, and planning reserve margins were developed and incorporated into the model. Factors such as existing patterns of transmission capacity and costs were also analyzed and incorporated into the model.

Once the necessary information and assumptions were incorporated into CEUM, model runs were conducted to ensure that the projections closely match actual experience for a selected year, in this case 1993. These runs used the information prepared for the base cases together with other inputs (*e.g.*, electricity demand) for the historical year. The purpose of this calibration process was to ensure that the model replicates historical experience. After the model was calibrated, it was run for each of the base cases, and then for each of the Rule scenarios for selected time periods.

To examine the impact of the Rule on regional attainment of ozone standards, additional air quality modeling was conducted using the UAM–V. UAM-V is a three-dimensional photochemical grid model that simulates the physical and chemical processes in the atmosphere that affect pollutant concentrations. It tracks emissions both geographically according to preset weather patterns and chemically over time. The UAM–V was used to create detailed air quality analyses for cases that might potentially create additional impacts from NO_X transport and ozone in the Northeast.

Rehearing Requests

The PA Com challenges the ability of computer modeling to simulate the effects of the Rule. It states that computer modeling is an attempt to reflect an approximation of reality that uses systems of linear equations, and that the airborne transport of pollutants in the atmosphere and the North American electric transmission grid are extremely large, complex nonlinear systems.[825]

The PA Com's challenge to the use of computer modeling also turns on the observation that models produce results that are dependent on the inputs and assumptions used in the models. The specific challenges to the inputs and assumptions used in the model are discussed separately below.

Commission Conclusion

We note first that computer models are the only available means of analysis that incorporate the range of factors that influence engineering and economic choices in the electric power industry, and the atmospheric chemistry and weather patterns that influence downstream air quality. We are mindful of the limitations of models, but the alternative of using no model at all—and hence making no analytic attempt to capture the complex economic and environmental factors—did not appear reasonable.

The PA Com does not explain how the Commission should otherwise simulate the effects of the Rule. Computer modeling may not be a perfect tool, but it is the best existing mode of analysis for this type of effort. The PA Com cannot merely assert that such modeling is inadequate. As the court noted in a similar context in *City of Los Angeles* v. *National Highway Traffic Safety Administration*, 912 F.2d 478, 488 (D.C. Cir. 1990), *overruled in part on other grounds, Florida Audubon Society* v. *Bentsen*, 94 F.3d 658 (D.C. Cir. 1996):

> Petitioners call for more ''analysis,'' but do not specify what they see as lacking or how ''analysis'' could supply the want. At some point—here after a seemingly full treatment—the agency must make a judgment. We discern no more from petitioners' argument than that they disagree with that judgment. Even were we to share their view of the matter, that would not be a sufficient basis for overturning the agency's decision.

Quoting *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 394 (D.C. Cir. 1973), *cert. denied sub nom. Portland Cement Ass'n* v. *Administrator, EPA*, 417 U.S. 921, 94 S.Ct. 2628, 41 L.Ed.2d 226 (1974), the court in *Northside Sanitary Landfill, Inc.* v. *Thomas*, 849 F.2d 1516, 1519 (D.C. Cir. 1988), *cert. denied*, 489 U.S. 1078 (1989), stated in like manner that:

> [C]omments must be significant enough to step over a threshold requirement of materiality before any lack of agency response or consideration becomes of concern. *The comment cannot merely state that a particular mistake was made * * *; it must show why the mistake was of possible*

[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).

significance in the results [the agency reaches]. (Emphasis in original).

The FEIS explains the Commission's conclusion that the environmental analysis of Order No. 888 is best conducted using the CEUM and UAM–V computer models. The PA Com cannot merely state that the use of such models is inappropriate. It must explain why this is so and what alternative method of analysis should be used. This it has not done. The request for rehearing is denied.

3. Transmission Assumptions

The FEIS recognizes the interdependence of interregional electric transmission transactions; accordingly, non-simultaneous interregional transfer capabilities estimated by the North American Electricity Reliability Council (NERC) were reduced for use in the model (*see* FEIS section 3.4.2). The analysis also considers the impact of the Rule on interregional transfers (*see* FEIS Tables 5–13 and 5–14), and the impact of changes in transmission capacity through sensitivity analysis.[826]

Rehearing Requests

The PA Com asserts that transmission usage in the FEIS is based on assumptions which are indeterminate to some degree. It states that historical interregional power transfers are used to estimate future transmission capabilities and capacity, and that while historical interregional electric transmission transactions have been large and complex, under the Rule the level of transactions will increase enormously. The PA Com claims that almost every time a new major interregional electric transmission transaction has occurred, there have been unpredictable flows of electricity in other regions that might be a thousand miles away. It concludes that relatively small changes in transmission flows can and have produced large harmonic transients and instabilities on the power grid.

The PA Com also contends that the relationship between the transmission usage price and the price of transmission service is unclear. It states that the development of the usage price seems circular, at least in part. It notes that model inputs were changed until the usage price coincided with an estimate of historical costs. The PA Com requests clarification of the development of the usage price assumption.

[826] FEIS at 3–8 through 3–11.

Commission Conclusion

The PA Com does not appear to understand the way the transmission usage price functioned in the analysis.[827] As explained in the FEIS, the CEUM model is annual and regional: it models a single year at a time using regions approximately the size of a state or large regions within a state.[828] Transmission in the model is represented as movement of power from one region to another. The model attempts to satisfy the demand for electricity at lowest cost—if there were no limitations on the movement of power from one region to another, the model would always generate power at the cheapest source and move that power to meet the demand. This result would clearly be unrealistic, since sources of power are limited in their ability to reach demand by limitations in the intervening transmission network. The transmission network in CEUM is represented primarily by the limitations that the transmission grid places on the ability of power to move freely to meet demand.

To use CEUM to provide a reasonable representation of transmission requires balancing the different ways in which the transmission system imposes limits on the movement of power. Flows on links between regions are limited by three general parameters in the model: losses, variable costs, and constraints on the quantity of capacity or energy that can be transferred. Losses are generally small, and are typically kept fixed from one model run to the next. Simulating transmission limits is largely a matter of balancing variable costs and quantity limits. True variable costs are usually assumed to be small, reflecting the low variable cost of operating the transmission system. Basic quantity limits are usually developed from NERC sources or other studies of the limits imposed by the physical operation of the transmission system.

[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.

[828] *Id.*

However, such limits do not always provide an adequate picture of current patterns of generation and transmission in the electric utility system. 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 CEUM, where flows are based on minimizing costs subject to physical constraints, the amount of power flowing from lost-cost sources of generation is typically overestimated.

The FEIS explains that there are two primary ways to address this difficulty when calibrating the model to represent historical power flows. One is to impose further limits on the quantity of power transferred within the model. The other is to raise the variable cost to simulate the effect of observed barriers to power flows between regions. The second approach was used by developing a ''usage price'' to raise the variable cost barriers in CEUM and supplement basic quantity limits derived from NERC estimates. This approach was taken because of its nexus to the primary effect of the Rule on transmission activities. The primary effect of the Rule on transmission will be to increase the ability of transmission users to gain access to transmission service and to permit users to develop flexible ways for buyers and sellers to use the transmission system efficiently. The primary effect is thus to remove institutional barriers to the use of the transmission system—in effect to reduce the transaction costs, or usage price, faced by those seeking access to transmission. Thus, the model was calibrated by selecting an initial set of usage prices and adjusting those prices until the model provided an accurate representation of historical generation and transmission patterns.

Usage prices (in mills per kWh) were developed by running CEUM for a historical period (1993). Starting from initial estimates of usage prices between CEUM regions, the model was run using historical inputs for 1993; the outputs from these runs were compared with the historical pattern of generation and transmission for that year. Usage prices were then adjusted until the pattern projected by the model was consistent with the observed historical pattern. The final adjusted prices were then used as the current usage prices.

Two rules were used to set the initial usage price estimates:

(1) For closely coordinated (*i.e.*, tight) pools, no separate usage price was assumed. This is consistent with the principle embodied in many pools that transmission

assets are to be treated as one system and used to minimize variable costs. Any allocation of the cost of service associated with transmission assets is typically treated as a fixed cost.

(2) Separate transmission costs are commonly applied in loosely configured pools. In many cases, these separate costs are derived on a MW-mile basis. Because the number of systems that have to be traversed within a loosely configured pool is generally small, the transmission usage price for areas with loosely configured pools were set to a small initial value (1 to 2 mills/kWh). Transmission across NERC regions may require traversing many utility systems, and for modeling purposes a charge of about 3 mills/kWh was assumed.

Applying this method required several runs of CEUM. Usage price changes were typically downward in areas where the initial prices were set at 3 mills per kWh, and prices after adjustment remained within the range of the initial usage prices. As a result, estimates of the current usage price varied from region to region after calibration, but generally fell within the range of 1 to 3 mills per kWh.

Thus, the concerns expressed by the PA Com were either considered in the FEIS, or are based on a misunderstanding of the method used.

4. Plant Availabilities and Heat Rates

The FEIS explains that power plant availability is the percentage of time that a generating unit is available to provide electricity to the grid, and that availability estimates for coal plants have an important effect on projected base case emissions because those estimates determine the amount of future generation expected from existing power plants.[829]

The base cases assume that average fossil-fuel plant availability rises to 85 percent by 2005 and then remains constant through 2010. This assumption reflects continuing efforts by utilities to improve plant availability. Between 1984 and 1993, coal plant availability increased five percent to nearly 81 percent. This trend is projected to continue through 2005 as electric generators respond to competitive pressures and opportunities extant without the Rule.

The FEIS explains that in the Competition-Favors-Coal Scenario, plant availabilities are assumed to reach 90 percent (as opposed to 85 percent in the base cases and other Rule scenarios) because competition is projected to lead to greater operational efficiency in generation markets. It notes that some older coal plants are not likely to reach this level without substantial capital investment. However, since 90 percent availability is achievable for many plants, this figure was selected as an upper bound to illustrate how much existing plants may be able to run if generation owners focus on meeting competition through greater use of coal plants.

The FEIS also explains that the base cases assume some deterioration in heat rates between life extension programs. In the Competition-Favors-Coal Scenario, existing generating plants are assumed to be better maintained so that there is no deterioration of heat rates between life extension programs. Except in the Competition-Favors-Gas Scenario, it is assumed that new combined cycle natural gas plants sustain existing heat rates (rather than improving as the next generation of gas technology comes on line). These assumptions reflect the fact that industry has put more effort into making better use of existing (disproportionately coal) plants rather than into improving the performance of new (almost entirely gas) plants.

Rehearing Requests

The PA Com challenges the plant availability assumptions used in the FEIS. It notes that the analysis assumes that generation plant availability will rise to 85 percent and that the Competition-Favors-Coal Scenario assumes that generation plant availability will rise to 90 percent by the year 2005. The PA Com states that although historical trends indicate that plant availability might increase, in reality as availability goes up it becomes increasingly difficult to obtain further improvements.

The PA Com contends that increasing availability to 85 percent would be surprising; an increase to 90 percent would be astonishing. It states that such increases would require a number of simultaneous technical advances, the likelihood of which are speculative. The PA Com argues that utilities in competition with each other may be less willing to fund and participate in cooperative research that leads to technical advances. The PA Com notes that maintenance staffs are being reduced as a result of cost reduction programs and that plant availability might decline as maintenance is deferred.

The PA Com also contends that the assumption in the Competition-Favors-Coal Scenario that heat rates do not degrade (go up) over time may be optimistic. It concedes that technological advances have produced dramatic improvements in heat rates, but states that it is unclear if this improvement is sufficient to overcome losses caused by backfitting emission control equipment. The PA Com notes that coal-fired generating stations in Pennsylvania have been required to install emission control equipment and that efficiency has been reduced in some cases, degrading the heat rate. It states that some coal stations have installed sulfur dioxide (SO_2) scrubbers which can reduce efficiency by five percent, and that other stations may be required to install selective catalytic reduction systems for NO_x or SO_2 scrubbers.

The PA Com contends that an additional limit on heat rate improvements is the age of generating stations and the fact that heat rates decline as stations age. It posits that this decline may be greater than the improvements that can be gained through technological advances.

Commission Conclusion

The PA Com's argument fails to consider the discussion of this issue in the FEIS.[830] Briefly, higher availabilities for coal plants were assumed in order to provide a scenario that was extremely favorable to the use of coal in existing facilities and hence a scenario that was most likely to have a larger environmental impact. The fact that some coal plants are able to maintain 90 percent availability is sufficient grounds for considering such a case, especially where the purpose of the assumption is to establish a reasonable range of potential environmental outcomes from the Rule.

With regard to the heat rate assumptions, the PA Com does not appear to understand how the assumptions functioned in the analysis. First, the factors it mentions (*e.g.*, efficiency reductions resulting from the addition of scrubber technology) are already considered in the CEUM model. Second, the CEUM does assume that heat rates degrade over time in the base cases. The assumption that they do not degrade in the Competition-Favors-Coal Scenario was made to simulate the relative improvement that might be achieved through potential effects of the Rule when competition is favorable to coal. As with certain other modeling assumptions challenged by the PA Com on rehearing, the heat rate assumptions used by the Commission are more conservative than those urged by the PA Com and thus demonstrate greater impacts from the Rule than would be the case using the assumptions urged by the PA Com.

[829] *Id.* at 3–18.

[830] Id. at J–63 and J–67.

5. Reserve Margins

The FEIS discusses the assumptions regarding planning reserve margins and their use in the model.[831] It states that planning reserve margins influence the amount of new capacity built and the mix of gas versus coal fired generation projected in CEUM. In particular, lower reserve margins tend to result in the construction of less capacity (typically, fewer gas-fired turbines and combined cycle units) and a somewhat greater utilization of existing coal units.

Generally, individual utilities set their reserve margins to comply with a technical standard established by the NERC sub-region. Typically, the NERC sub-region might determine that a one day in 10 years loss of load probability (LOLP) is the appropriate standard. Individual utilities within the sub-region would determine their reserve planning margin to be consistent with this standard after accounting for tie capabilities. NERC sub-regional studies are performed periodically to determine whether the reliability standard is being satisfied for the planning horizon given planned capacity additions. The tie capability between the sub-region and other regions is accounted for in reliability studies at the NERC sub-regional level.

The FEIS notes that in recent years, reserve margins typically have been revised downwards, although the planning standard itself (most commonly the one day in 10 years LOLP) has not been changed. Three reasons support the downward revision in reserve margins: (1) An expected improvement in unit availability; (2) anticipated shifts in utility load shape towards a lower load factor; and (3) an increase in the number of generating units.

FEIS Table 3–4 summarizes the reserve criteria and associated planning reserve margins that have been derived from the most recent annual planning documents prepared by the reliability councils. It states that a review of current planning documents shows that utilities expect planning reserve margins to decline over time. One factor identified as contributing to this decline is the expectation that availability will improve appreciably as utilities are subject to performance-based regulation and experience greater competition.

Additionally, some utilities have revised their planning reserve margins to account for ties in other regions. In some cases, utilities have updated their planning reserve margin calculation to reflect current estimates of customer willingness to pay for increase reliability.

Based upon a review of utility expectations, the FEIS concludes that an appropriate base case assumption is for planning reserve margins to decline by 2005 to the lower end of the applicable ranges set forth in FEIS Table 3–4.

Rehearing Requests

The PA Com challenges the reserve margin assumptions used in the model. It asserts that the assumption that reserve margins will fall to fifteen percent by 2000 and (in one scenario) to thirteen percent by 2005 is based in part upon the assumption of increased generation plant availability across the board. The PA Com notes that this increase in availability might not occur. It states that as wholesale transactions increase under open access, some, but not most, utilities will be able to reduce reserve margins and still maintain reliability. The PA Com asserts that many utilities cannot reduce reserve margins because available transmission capacity between regions is already being utilized to the maximum extent possible. It concludes that reserve margins for certain individual utilities could decline, but this alone would not reduce required reserve margins for all utilities to the levels that are assumed in the model.

Commission Conclusion

The reserve margins used in the base cases were set using current utility plans and trends in the industry. Reserve margins for the competition scenarios were set slightly lower, reflecting the potential for decline in a more open competitive environment. The PA Com acknowledges the potential decline, but claims that not all utilities will be able to reduce reserve margins to the levels assumed. However, the FEIS addresses such differences by using different regional assumptions about reserve margins and different reserve margins in each region. The PA Com's concern is therefore without basis.

6. Northeast MOU

The FEIS assumes that power plants in the Northeast Ozone Transport Region (OTR) will comply with Phase II of the Northeast Memorandum of Understanding (MOU). The MOU establishes NO_X tonnage limits during the five-month ozone season (May-September) for electric generating and large industrial services and allows for emissions trading.[832] The FEIS states that compliance with Phase III of the MOU was not assumed since its implementation is optional, depending on final attainment status with regard to Clean Air Act requirements.

Rehearing Requests

The PA Com states that the base cases and scenarios assume that no NO_X controls will be required for Title IV group II boilers, that phase II of the MOU will be implemented, and that no additional requirements will be imposed. The PA Com contends that phase III of the MOU might be implemented, and that if this occurs and upwind generation is not required to control ozone precursors, cleaner generation in the Northeast may be displaced by increased generation from outside the OTR.

Commission Conclusion

In essence, the PA Com appears to be raising an emissions disparity argument rather than posing a challenge to the modeling assumptions used in the FEIS. The emissions disparity argument is addressed below.

7. Natural Gas Prices

Average wellhead natural gas prices for the High-Price-Differential Base Case were based on a recent forecast of natural gas acquisition prices by Wharton Econometric Forecasting Associates (WEFA).[833] This forecast projected at that time that natural gas prices would increase in real terms (1994 dollars) to $1.83 per MMBtu by 2000, and rise to $2.42 per MMBtu by 2010. The forecast was selected as representative of a number of natural gas price forecasts that were made during that time.

CEUM requires delivered, not wellhead or acquisition, prices as an input. Delivered natural gas prices for each Census region were derived from the weighted average transportation mark-ups reported by the Energy Information Administration (EIA) in *Natural Gas Monthly* for each Census region. The *Natural Gas Monthly* provides a consistent historical series of wellhead and delivered prices for calculating historical transportation margins. These margins were assumed to remain constant throughout the forecast period.

In the Constant-Price-Differential Base Case, delivered gas prices were assumed to equal current delivered spot prices in each region. To maintain a constant gas price relative to coal, these prices were assumed to decline from current levels

[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.

at the same rate as coal prices decline in CEUM.[834]

Rehearing Requests

The Joint Commenters assert that the fuel-price assumptions used in the model unduly favor the use of natural gas as a fuel and appear to understate adverse effects.

In particular, the Joint Commenters claim that the two alternative fuel-price cases use the same coal price assumptions. It states that the Competition-Favors-Coal Scenario is supposed to demonstrate the effects of economic assumptions that favor coal, but that this case actually uses price assumptions that reflect the lowest natural gas price of the projections cited in the FEIS. It states that the FEIS should have used projections less favorable to natural gas: for example, $2.51 per MMBtu in 2000 (Gas Research Institute) and $3.37 per MMBtu in 2010 (Energy Information Administration). Put differently, a more appropriate Competition-Favors-Coal Scenario would have used the projected highest reasonable natural gas prices relied on in the FEIS.

The Joint Commenters then claim that the Constant-Price-Differential Base Case is based on gas price assumptions that are far below the projected prices cited in the FEIS.[835] According to the Joint Commenters, this case assumes natural gas prices of $1.67 per MMBtu in 2000 and $1.57 per MMBtu in 2010. It asserts that these estimates are approximately 10 and 54 percent lower in years 2005 and 2010, respectively, than the lowest forecasts cited. A more appropriate Competition-Favors-Gas Scenario would have used the WEFA forecasts that contain the lowest reasonable projected gas prices.

Commission Conclusion

The claim that the assumptions unduly favor natural gas prices is incorrect. First, the assumption that lower gas prices will reflect favorably the environmental effects of the Rule is not valid. The impact of the Rule when gas prices are constant relative to coal is very close to the impact when gas prices are high relative to coal.[836] For example, the impact on total NO_X emissions in 2005 is higher when gas prices are constant relative to coal than when gas prices are high relative to coal (88,000 tons for the Constant-Price-Differential Base Case versus 55,000 tons for the High-Price-Differential Base Case).[837]

Second, the two price series were selected to give a range of variation in emissions that reflect differences in the price of gas relative to coal, rather than to project a ''correct'' natural gas price. As discussed in the FEIS, the Constant-Price-Differential Base Case reflects a continuation of the historical relationship between gas and coal prices over the past 10 years. Appendix G shows how forecasts over this period have consistently overestimated the price of gas relative to coal. It is therefore reasonable to consider the Constant-Price-Differential Base Case as one side of a reasonable range.

The prices selected for the other side of the reasonable range of gas prices relative to coal (the High-Price-Differential Base Case) were based on current forecasts at the time of the analysis. There were two primary reasons for selecting a lower gas price from the range of existing forecasts. First, the CEUM coal price forecast is determined within the model and could not be changed as an input. This coal price forecast was lower than the coal prices assumed in other forecasts. By picking a gas price forecast at the lower end of the range of current forecasts, and combining this forecast with the lower coal prices forecasts in CEUM, the analysis assumed a typical price of natural gas relative to coal.

Second, at the time the analysis was conducted, all major forecasting organizations stated that they expected their gas price forecasts to be lower. However, these organizations did not complete their forecasts for several months. Since the available forecasts were up to a year old, there was reason to believe the forecasts overstated the current thinking among forecasters regarding future natural gas prices. This reason was confirmed by the forecasts that appeared around the time the analysis was completed. For example, the forecast for the wellhead price of natural gas in the year 2010 from the EIA published in January 1996 was $2.10 per million Btu, 15 percent below the forecast of $2.42 assumed for the High-Price-Differential Base Case in the FEIS.

8. Expanded Transmission Analysis

Several commenters on the DEIS expressed concern that increases in transmission capacity resulting from open access might increase generation levels and thus air pollution. In response, the FEIS examined scenarios that increased transmission capacity substantially beyond current levels—including increases that the Commission believed would far exceed any transmission capacity increases that might occur as a result of the Rule. This analysis found that postulated increases in transmission do not affect emissions attributable to the Rule. The Commission also found that issues regarding enhancement of existing lines are more complex, and that this is due in part to the fact that state-level siting issues, the principal barrier to major increases in the transmission grid, are unaffected by the Rule. While competition will lead to improved efficiencies in generation, transmission will remain a regulated monopoly function. The Rule will reduce barriers to access, but will not open the transmission system to direct competition. Thus, the Commission concluded that the competitive effects of the Rule on transmission will be relatively small.[838]

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The Joint Commenters claim that the expanded transmission analysis is unduly conservative. It states that the Commission increased peak transmission usage from 75 percent of first contingency total transfer capability (FCTTC) to 105 percent of FCTTC, and that this expanded transmission analysis represent minimal actual expansions, the most extreme of which barely increases FCTTC above current levels by the year 2010. The Joint Commenters claim that the Commission should have examined additional expansion potential in those analyses that more accurately demonstrate the effects of transmission expansion.

Commission Conclusion

The Joint Commenters' claim that the expanded transmission analysis is inadequate is based on the premise that the FEIS used the wrong assumptions in developing transmission capacity. Joint Commenters contend that 100 percent of the FCTTC should have been used in CEUM. We believe that the use of 75 percent of this capacity to reflect annual capability is the appropriate level for modeling purposes. This reduction factor is necessary because the capability must be simultaneous systemwide capability and it must be sustainable. The FCTTC is a non-simultaneous ''snapshot'' transmission capability. The total simultaneous transfer capability is not accurately represented by adding together the

[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.

[837] *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.

maximum transfer capability of each line in the system. The transmission system is a system. Loading on one line affects loading capability on all other lines in the system. This is especially true if the calculation is for capability over an extended period of time, as is the case with the FEIS, which uses transfer capability over one year. ''Derating'' as it has been called, is a reasonable way to represent the fact that a transmission system is capable of carrying less than the sum of the capabilities of the individual lines. Further, when modeling, if the model is calibrated so that the system is carrying actual historical flows—no matter what factor is used—the system will be carrying at or near its maximum capacity at constrained points which are the only points on the system where increased capacity would produce increased flows. As a result, increasing the transfer capability factor by up to 40 percent, as is done in the sensitivity analyses in Chapter 6 of the FEIS, represents a large change in the capability and use of the transmission system. Moreover, we note that this methodology has been used in previous CEUM analysis, where it was subject to review by electric utility experts.[839] For these reasons, the Joint Commenters' criticisms are invalid.[840]

The Joint Commenters challenge the assumptions used in the Commission's expanded transmission analysis as ''unduly conservative'' and ''represent[ing] minimal actual expansions.'' Joint Commenters fail to explain in what respect they deem the expanded transmission analysis to be inadequate. They fail even to respond to the matters discussed by the Commission with regard to this issue in Order No. 888.

As we noted above in the discussion of the PA Com's argument that the Commission failed adequately to consider the alternative of instituting open access pursuant to section 211 of the FPA, it is insufficient for a party to complain that an analysis is inadequate without providing specifics.

C. Mitigation

The FEIS and Order No. 888 extensively assess the need for mitigation and discuss potential mitigation measures, including proposals advanced by commenters.[841] This discussion is perhaps best summarized by the conclusion to Chapter 7 of the FEIS, which states that:

This FEIS shows that the proposed rule is expected to slightly increase or slightly decrease total future NO_X emissions, depending on whether competitive conditions in the electric industry favor natural gas or coal. The insistence of commenters that the Commission adopt and implement mitigation measures is based on significantly overstated assumptions regarding the contribution of the proposed rule to the existing environmental problems. The analysis presented in Chapter 6 establishes that overstated assumptions about the impact of the proposed rule are simply wrong.

Nonetheless, in light of the importance of this issue, we have examined potential mitigation measures in detail, including those proposed by commenters, to ensure that environmental consequences of the rule have been fully and fairly evaluated. We do not believe mitigation should be undertaken in this rule because:

Any mitigation measures the Commission might undertake are not justified by the small impacts of the rule, which impacts are as likely to be beneficial as they are to be harmful;

The impacts of the proposed rule are dwarfed by the far larger ozone and NO_X emission issues that either have nothing to do with the electric industry or will be unchanged by the rule or the larger open access program. We believe that it would be ineffective to address the NO_X and ozone issues in a piecemeal way;

The NO_X issue is part of a long-standing, difficult set of inter-regional environmental issues. Representatives of many interests in both the Northeast and the Midwest have invested substantial efforts towards finding acceptable solutions through the OTAG process. Any mitigation the Commission might undertake could usurp EPA's mandate under the Clean Air Act and undermine progress towards comprehensive solutions sought by OTAG. This is not justified by impacts that are small and just as likely to be positive.

We do not agree that the frozen efficiency reference case should be substituted for the EIS base cases or that competitive forces will favor coal over the next 15 years. But even accepting those assumptions, emissions attributable to the rule are relatively small until well after the turn of the century. So, even accepting such assumptions, the staff believes it would be unreasonable for the Commission to adopt mitigation requirements as part of the final rule; to do so would be tantamount to assuming that EPA and OTAG will not implement reasonable control measures in the next ten to 15 years;

The Federal Power Act and NEPA, either singly or conjointly, do not authorize the Commission to adopt and implement the proposed mitigation measures. The Commission does not possess (and has no mandate to possess) expertise on the extremely difficult issues involved in atmospheric chemistry and transport. It is fundamentally a economic regulatory agency. As a result, any mitigation measures the Commission undertook would be based on less-than-ideal information and analysis. It is unreasonable for the Commission to attempt such mitigation given the impacts found in this FEIS. This is especially true in light of the substantial additional research that EPA and OTAG are undertaking on the basic nature of the problem;

Some suggested mitigation measures that might work at the transaction level would undermine the purpose of the rule. There is no justification for endangering the substantial benefits projected from the rule to mitigate a problem that might not exist and that is, in any case, likely to be small.[842]

The FEIS goes on to note that the long-term existence of a significant ozone nonattainment problem in parts of the country has led to the development of mechanisms to address this issue. It states that any incremental increases in NO_X emissions that may result from the Rule can be addressed within this existing framework. In particular:

The Clean Air Act authorizes EPA to establish transport regions that are charged with assessing the degree of interstate transport of pollutants, assessing mitigation strategies, and recommending revisions to State Implementation Plans to correct the problem. The Clean Air Act specifically establishes an ozone transport region for the Northeast. The jurisdictions that comprise the OTR have developed a coordinated approach to this problem that includes adopting a regional cap on NO_X emissions.

Although the OTR process is achieving its purpose, the problem is larger than the OTR can address. As a consequence, the Ozone Transport Assessment Group has been formed which encompasses the OTR and upwind states that contribute to nonattainment. OTAG is performing extensive photochemical grid modeling of the eastern U.S. to determine ozone transport patterns and to evaluate the efficiency of various control strategies. OTAG is considering imposing a cap and trade system for NO_X emissions in a 37-state area comprised of the Northeast OTR and upwind states. If the cap and trading system becomes

[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.

[840] *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.

effective it should fully mitigate NO_X emission increases, if any, attributable to open access transmission within the 37-state area. A cap and trade program is also likely to mitigate CO_2 and mercury emissions.

We believe that the cap and trading system under consideration in the OTAG process is the preferred approach to the overall NO_X emissions problem. The OTAG process brings to the table the parties that must participate in making the difficult decisions to fully resolve this problem. The OTAG process possesses the technical resources and expertise to address the difficult scientific and technical issues that must be resolved to remedy this problem. More limited approaches cannot render a satisfactory solution. We respect the expertise and the goals of the OTAG process and do not believe we can or should substitute for them in addressing this long-term national problem.[843]

Rehearing Requests

Pennsylvania PUC. The PA Com claims that the Commission has inappropriately declined to assume any responsibility for mitigating environmental impacts associated with the Rule. It states that the Commission has authority to take mitigation measures related to its regulatory actions and that the Commission can reasonably add environmental impacts to the list of factors to be weighed under the FPA's public interest standard. In this regard, it contends that the FPA grants FERC authority to place conditions on the regulation of rates and conditions of wholesale power sales and the interstate transmission of electric power as well as to order wholesale wheeling under certain circumstances.

The PA Com states that the Commission should act to minimize the likelihood of significant additional NO_X emissions by developing a mitigation plan to be implemented in conjunction with the Rule, and that FERC should use the results of the OTAG process to provide information to develop this strategy. The PA Com concludes that FERC should not require open access generically.

Vermont Department of Public Service. The Vermont Department of Public Service (VT DPS) contends that the Commission erred in failing to establish a monitoring program and a periodic reopener provision to address environmental considerations. VT DPS submits that the Commission has given inadequate consideration to the possibility that the Rule may unnecessarily exacerbate environmental impacts. It notes EPA's claim in its referral letter to the Council on Environmental Quality (CEQ) that any future NO_X increases resulting from open access would exacerbate the difficulty of accomplishing reductions in NO_X emissions.

VT DPS claims that the environmental review process has not facilitated the ability of affected parties to review all modeling assumptions. It also claims that other environmental reviews suggests more serious NO_X emission consequences of the Rule than acknowledged by the Commission.

VT DPS states that given the possibility that the FEIS conclusions may prove wrong, the Commission should take steps to permit timely reevaluation of its program. VT DPS recommends that the Commission establish an ongoing monitoring program to determine if the Rule poses an unacceptable risk to air quality. It states that a monitoring program would allow the Commission to take timely action to mitigate any unintended consequences of the Rule. The Commission should also provide for periodic reevaluation of the Rule's open access provisions and should commit to a comprehensive reevaluation of the Rule's environmental impacts every five years over the next 20 years.

New York Attorney General. The New York Attorney General (Attorney General) states that the federal government should ensure that New York and other Northeast states do not bear the burden of any increased air pollution resulting from deregulation.[844]

The Attorney General asserts that utilities in upwind states have a competitive advantage relative to Northeast utilities because they are subject to less extensive environmental controls. The Attorney General contends that deregulation may result in these plants increasing generation, thus increasing emissions that will contribute to the inability of New York and the Northeast to meet the federal ozone standard. The Attorney General claims that, regardless of the effects of the Rule, studies show that a 50 percent reduction in NO_X emissions from all sources east of the Mississippi will be necessary for New York and other Northeast states to achieve the ozone standard.

The Attorney General states that Congress has placed limits on EPA's authority to protect New York from upwind emissions, and that it is therefore essential that FERC exercise any authority it may have to mitigate the environmental effects of the Rule.

The Attorney General claims that EPA's proposal in its February 20, 1996 comments to place a cap on NO_X emissions would mitigate the effects of the Rule; it suggests basing this system on the MOU pursuant to authority residing in EPA and/or FERC. Under this proposal, a utility would be permitted to take advantage of deregulation if it simultaneously takes steps to prevent emission increases.

Joint Commenters—Overview. The Joint Commenters state that FERC has failed to consider and disclose the potential environmental effects of the Rule, and that FERC's decision that it lacks authority to implement mitigation is contrary to law.

The Joint Commenters' premise is that, despite deficiencies in the Commission's analysis which understate the effects of the Rule, the FEIS nonetheless presents data confirming that open access will have significant adverse environmental impacts. Joint Commenters posit that increased emissions from open access could seriously threaten achievement of Clean Air Act requirements and other environmental commitments. It reasons that the Commission therefore must develop and implement environmental mitigation.

The Joint Commenters begin with the assertion that the data presented in the FEIS do not support the conclusion that the effect of the Rule on air pollution will be insignificant. It claims that the Commission relied on cases that show small impacts. Joint Commenters note in this regard that EPA has determined that any increase in NO_X emissions from restructuring is unacceptable and should be remedied.

Joint Commenters then assert that FPA sections 205 and 206 require the Commission to adopt mitigation. It claims that case law supports the proposition that both NEPA and the FPA authorize FERC to mitigate the adverse environmental impacts arising from its action. Even assuming *arguendo* that it was reasonable for the Commission to reject specific proposed mitigation measures, it is unreasonable the deny the existence of authority to mitigate. The Commission should remedy this by adopting mitigation concurrent with implementation of Order No. 888.

According to Joint Commenters, the FEIS establishes that competitive electric markets will likely result in higher utilization of heavily polluting coal-fired generation. Thus, in view of EPA's statement in its referral to CEQ that any increase in NO_X emissions could seriously undermine attainment of health based standards, the FEIS

[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.

finding that emission increases that may be as large as 315,000 tons per year are insignificant is not supported by the record.

Joint Commenters then argue that not only does the decision not to implement mitigation measures risk nonattainment of public health goals, it will fail to achieve the regulatory objective of fair and efficient bulk power competition. It contends that without concurrent environmental mitigation, the Commission will put in place a market structure that is inherently discriminatory and that arbitrarily shifts costs. It states that Order No. 888, in effect, provides a class of competitors with an undue preference subsidy. This undue preference results from the fact that the owners of coal-fired generation that are not subject to emissions regulation will be able to shift financial responsibility for their pollution to competitors in downwind regions. This discriminatory situation will distort the bulk power market and produce inefficiencies that the Commission has not addressed.[845]

Open Access Will Have Significant Adverse Impacts. The Joint Commenters state that some FEIS scenarios show that restructuring is likely to have significant adverse environmental effects. It claims that the sensitivity analyses confirm that low-cost, high-emission coal plants may increase their capacity utilization from an average of 62 percent in 1993 to 81.5 percent by 2010 and that this increase is associated with an additional 515 billion kWh of coal generation per year by 2010 above 1993 levels, assuming expanding transmission. FEIS data further indicate that 110 billion kWh of this annual increase by the year 2010 will be attributable to competition under the open access policy compared to the frozen efficiency case.

The Joint Commenters assert that the FEIS also confirms that this increase in coal-based generation will increase NO_X emissions across the 37-state OTAG region by 250,000 tons per year by 2010 (315,000 tons for the entire U.S.) and result in a cumulative NO_X emissions increase across the U.S. of 530,000 tons by 2000 and 2.7 million tons by 2010.

The Joint Commenters assert that the impacts of a 250,000 ton NO_X increase across the OTAG region are extremely significant, particularly in downwind nonattainment areas, and fly in the face of EPA's determination that any increase is unacceptable.

The Joint Commenters contend that the Commission understates the significance of these numbers by emphasizing percentages and using national figures. According to Joint Commenters, the FEIS demonstrates that regional increases in NO_X include a seven percent increase in the East North Central region, 10 percent in the Mountain region and 26 percent in the Pacific regions. These references are to emissions in 2005. The percentages in the year 2010 are approximately five percent nationally, rather than the three percent discussed in Order No. 888.

The Joint Commenters state that the FEIS also shows that increased utilization of coal plants could significantly add to utility carbon dioxide (CO_2) emissions, which would conflict with the Clinton Administration's commitment to stabilize greenhouse gas emissions at 1990 levels by the year 2000. It states that the Competition-Favors-Coal Scenario projects that annual utility CO_2 emissions will increase by 285 million tons by 2000 and by 737 million tons by 2010; and that the FEIS attributes about 10 percent of the increase to the Rule. It argues that this increase will threaten international commitments of the U.S. Government. The Joint Commenters assert that utility CO_2 emissions are not currently on track to fulfill national and international climate protection objectives and open access competition, to the extent it favors existing coal plants, will exacerbate these trends.

The Joint Commenters then claim that in addition to the emissions impacts that are identified in the FEIS, EPA's technical analysis indicates that the Rule has the potential to cause much larger impacts than the FEIS estimates for the Competition-Favors-Coal Scenario. EPA's evaluation, which Joint Commenters claim does not incorporate worst case scenario assumptions, indicates that the potential increases in NO_X emissions from open access could be more than twice the increases projected in the FEIS Competition-Favors-Coal Scenario in years 2000, 2005 and 2010. The potential that FERC's highest polluting case understates emissions increases to this extent illustrates the uncertainty surrounding the impacts of open access, particularly the uncertainties surrounding the accuracy of the Commission's estimates, and the critical importance of developing mitigation programs.

Authority to Mitigate. The Joint Commenters assert that the Commission's rejection of authority to mitigate environmental impacts is contrary to law and arbitrary and capricious. It states that the Commission's rejection is inconsistent with Commission claims about its sections 205 and 206 authority, and that both NEPA and the FPA permit FERC to mitigate adverse environmental impacts. Thus, while it may be reasonable for the Commission to reject specific mitigation measures, the Commission's decision that it lacks authority to implement mitigation constitutes an arbitrary and capricious exercise of agency authority.

The Joint Commenters argue that NEPA authorizes agencies to consider and address environmental impacts so long as any actions undertaken do not conflict with the agency's authorizing statute. It states that a number of cases support the proposition that FERC's FPA authority is broadened by NEPA—that NEPA policies and goals inform and expand the FPA's definition of public interest. In effect, NEPA establishes a legal nexus between the Commission's primary regulatory duties and environmental protection. Thus, courts have upheld agency mitigation actions under NEPA even when the agencies have no explicit environmental protection mandate. The Joint Commenters assert that the Commission did not address these cases in concluding that it lacks authority to mitigate adverse environmental impacts under sections 205 and 206 and the FPA's general public interest standard.

The Joint Commenters assert that if NEPA is to be given practical effect, agencies must have authority to do more than study the potential environmental impacts of proposed actions. To interpret and administer federal laws in accordance with NEPA policies, agencies must have the authority to use their statutory powers in ways that implement NEPA policies. The arena of permissible environmental action is constrained only by the limits of the agency's jurisdictional authority under its enabling statutes. Thus, the only limits on FERC's ability to implement environmental mitigation are those defined by the FPA. Therefore, the question is whether mitigation falls within the regulatory powers of FERC.

The Joint Commenters argue that the FPA authorizes the Commission to mitigate the environmental effects of its actions, stating that the public interest standard of FPA section 201 encompasses the environmental and other competitive concerns discussed in its request for rehearing. The Joint Commenters state that *NAACP* v. *FPC,* 425 U.S. 662 (1976) and similar cases establish that FERC has jurisdiction to address environmental concerns since such concerns are directly related to FERC's regulation of economic interests in the electric industry.

The Joint Commenters assert that FERC's duty to ensure just and

[845] This aspect of the Joint Commenters' argument is addressed below.

reasonable rates that are not unduly discriminatory or preferential also encompasses non-economic factors in appropriate circumstances. It argues that the Commission's reliance on *Office of Consumers' Counsel* v. *FERC,* 655 F.2d 1132 (D.C. Cir. 1980), to support its narrow reading of the FPA's public interest standard is misplaced.

The Joint Commenters then take issue with the position that the Commission lacks authority to implement mitigation because it has insufficient expertise in air pollution control and because Congress gave EPA authority to address such issues. It states that the record does not support a conclusion that FERC lacks the expertise necessary to provide for mitigation of the Rule's impacts. Moreover, nothing would prevent the Commission from acting in concert with EPA to take advantage of EPA's expertise.

The Joint Commenters state that, unlike the situation in *Office of Consumers' Counsel,* Congress has given FERC, along with EPA and other federal agencies, the responsibility to address the environmental effects of its actions. In this case, Joint Commenters are asking the Commission to mitigate the environmental impacts of its Rule, not to assert jurisdiction proactively over air pollution matters or to usurp EPA's role. Under Order No. 888's logic, no federal agency would have authority to mitigate the environmental impacts of its proposed actions because EPA is the primary agency with environmental expertise and responsibility.

The Joint Commenters then argue that the Commission's jurisdiction to consider environmental issues also derives from a traditional analysis of FERC's jurisdiction over wholesale power rates. It states that if the Commission does not allocate environmental responsibility to high-emission utilities, environmental compliance costs will be transferred to downwind utilities and their customers. These utilities will be required to incur costs to reduce emissions and must increase rates to recapture these costs. Thus, Order No. 888 will directly affect the costs that are included in electric rates, which the Commission has authority to review under sections 205 and 206.

The Joint Commenters conclude their discussion by noting that, while it may have been reasonable for the Commission to reject specific mitigation proposals, the Commission should reexamine the position that it has no authority in this area and instead acknowledge that the exercise of that authority is not warranted here given the conclusions in the FEIS. The Joint Commenters go on to note that EPA proposed in its referral to CEQ a mitigation approach that seeks the Commission's commitment to future actions and outlines immediate actions EPA will take to address the potential NO_X emission increases identified in the FEIS. The Joint Commenters state that although it believes EPA's proposal is reasonable and strongly support the tracking system recommended, the Commission should develop a backup NO_X mitigation mechanism by the end of 1996 to assure that Order No. 888 will be implemented without adverse environmental impacts.

Commission Conclusion

Need for Mitigation. The FEIS examines fully claims that the Rule will have significant environmental impacts requiring mitigation. As stated in Order No. 888:

First, the findings show that, without the rule, NO_X emissions are expected to decline until at least the year 2000. Thereafter, again without the rule, NO_X emissions are expected to increase steadily through the year 2010 (the end of the FEIS study period). The extent of the decrease and the increase will be largely determined by the relative prices of natural gas and coal, the two main fuels used to generate electric power in most regions.

In reaching this conclusion, the FEIS used two ''base'' cases. In one (the ''High-Price-Differential Base Case''), natural gas was assumed to become substantially more expensive compared with coal than it is today. In the other (the ''Constant-Price-Differential Base Case''), natural gas was assumed to maintain essentially the same price relative to coal that has existed for the last ten years. The two cases describe the range of emissions due to fuel price uncertainty without the rule and demonstrate the overall trends of decreases until 2000 and increases thereafter.

Second, the FEIS finds that the rule will not in any significant respect affect these overall trends.

The potential impact of the rule was studied initially under two scenarios. In one (the ''Competition-Favors-Gas Scenario''), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor natural gas as a fuel. In this scenario the effect of the rule is slightly beneficial. Total NO_X emissions are reduced overall by about two percent nationwide from the base cases. In the other (the ''Competition-Favors-Coal Scenario''), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor coal as a fuel. In this scenario the effect is again slight, showing approximately a one percent increase in NO_X emissions nationwide from the base cases. In both scenarios, however, the rule does not have an overall effect on NO_X emission trends.

Stated differently, under any case studied, with or without the rule, there will be an overall net decrease in NO_X emissions through the year 2000. Thereafter, NOx emissions begin to increase. The rule does not materially affect either the decline prior to 2000 or the increase thereafter.

Based on these findings the Commission concludes that a comprehensive, Commission-imposed mitigation scheme to address the environmental consequences of the rule is not appropriate. If competition favors gas, the effects are beneficial and mitigation is unnecessary. If competitive conditions favor coal through the year 2010, and NO_X emissions increase slightly as a result of the rule, these minor effects would be effectively mitigated as a part of a comprehensive NO_X cap and trading allowance scheme developed by EPA in cooperation with the Ozone Transport Assessment Group (OTAG) and administered by EPA and state environmental regulators under the clearly established authority of the Clean Air Act. [846]

The Commission went on to note that it believes the appropriate no-action alternative was used to conduct this analysis. ''An alternative that requires the Commission to reverse all its other open access policies is simply not a 'no-action' alternative. To the contrary, it would require decisive action running counter to the direction from the Congress in the Energy Policy Act and the needs of the marketplace and electricity consumers.'' [847] The Commission then explained:

However, to ensure that the effects of the rule were analyzed fully, the FEIS did study a reference case based on the ''frozen efficiency'' case proffered by EPA and the Department of Energy (DOE). Although, as described below, we believe this case to be highly unlikely, the results show that, even under this scenario, the impacts of the rule are not great and do not vary significantly from those projected by staff under the other assumptions.

In one case requested by EPA, staff studied a combination of assumptions most likely to show significant increases in emissions associated with the rule; the case included EPA's frozen efficiency scenario, coupled with the ''Competition-Favors-Coal'' assumptions. Other cases requested by EPA posit dramatic increases in transmission capacity (that we find highly unlikely). Even this combination of assumptions—geared to demonstrate the greatest impact the rule might have on increased NO_X emissions—produced little in the way of environmental consequences associated with the rule. Under these extreme (and unlikely) conditions, there would still be a net decrease in NO_X emissions until at least the year 2000, albeit a smaller decrease than in the base cases. Comparing projections of emissions for the same years, emissions would be higher than the base cases only by two percent in 2000 and three percent in 2005. It is only in the year 2010, assuming these improbable scenarios, that NO_X emissions associated with the rule would be higher than the base case by even five percent.

[846] FERC Stats. & Regs. at 31,862–63; *mimeo* at 663–65 (footnotes omitted).

[847] *Id.* at 31,863; *mimeo* at 665.

Based on these studies, including the EPA reference case, the Commission endorses the staff findings that the rule will affect air quality slightly, if at all, and that the environmental impacts are as likely to be beneficial as negative. This is true even under scenarios contrived to maximize emissions associated with the rule under circumstances that this Commission believes to be highly unlikely.

Importantly, this is also true in the near- to mid-term. Until the year 2010, even the worst case (the frozen efficiency case) produces results very similar to those produced using assumptions the Commission believes to be reasonable. In short, the rule will not produce an ''ozone cloud'' coming across the Appalachians to threaten the Northeast on the day the rule goes into effect. Assuming that any environmental impacts occur, they are years in the future and may well be beneficial. As a result, calls for Commission mitigation, and in particular for interim mitigation to ''fill the gap'' until programs under the Clean Air Act can be adopted, are unnecessary and disproportionate to the possible effects of the rule. [848]

Thus, there is no basis for claims that the Rule will result in large increases in pollution from generating plants operating under less stringent environmental controls. This negates arguments calling for the imposition of mitigation measures to ensure that all entities compete under an identical regulatory regime.

We note in this regard that the Joint Commenters' claim that the Rule may result in emissions increases as large as 315,000 tons per year by the year 2010, and cumulative NO_X increases across the United States of 530,000 tons by 2000 and 2.7 million tons by 2010, is incorrect. The Joint Commenters derive this result by selectively choosing numbers from the FEIS, comparing sensitivity cases designed to be unrealistically low and high extremes. The low emissions case selected is the frozen efficiency case that represents a complete reversal of current industry and regulatory trends that are occurring without the Rule. The high emissions case represents an increase in transmission capacity that cannot reasonably be ascribed to the Rule. The FEIS indicates that these cases were used to examine the sensitivity of findings to certain extreme assumptions maintained by commenters and are not the appropriate cases to use for considering potential environmental impacts from the Rule.

Moreover, the Joint Commenters reference increases from the Rule without noting equally likely decreases. Even with the lower emissions resulting from the unrealistic frozen efficiency case, the FEIS finds decreases in emissions from the Rule when competitive forces lead to greater efficiency for natural gas generation compared to coal.

Actions to Mitigate NO_X Emissions. Moreover, EPA and the Commission have committed to undertake the actions sought by those seeking rehearing on this issue. EPA in its referral to the CEQ concurred with the Commission ''that the open access rule is unlikely to have any significant adverse environmental impact in the immediate future, and that in light of its anticipated economic benefits, implementation of the Rule should go forward without delay.'' EPA also ''concludes that the FERC has conducted an adequate analysis under the National Environmental Policy Act of the environmental impacts of the open access rule under a range of possible scenarios.'' In particular, EPA concurs that the ''FERC made a reasonable choice of models (CEUM) and made assumptions for various factors input into the model that lie within the range of reasonable assumptions.''

EPA also concurred with the Commission that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This includes support for the efforts of OTAG to develop standards for measuring the scope of the ozone transport problem and developing emissions reduction strategies.

More significantly, EPA committed to use its authority under the Clean Air Act to support successful completion of the OTAG process. EPA will establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans ''if some States are unable or unwilling to act in a timely manner.'' [849]

EPA also states that if ''the OTAG and Clean Air Act processes fail to produce the necessary pollution limitations in a timely manner, EPA will call upon all other interested Federal agencies to assist in solving the problem.'' In this context EPA would ask the Commission to contribute by further examining, through a Notice of Inquiry, possible strategies for mitigating NO_X emissions increases associated with the Rule. EPA also suggested that if it determines that the problem must be addressed through EPA initiation of Federal Implementation Plans, FERC could then initiate a rulemaking to propose ''suitable means under the Federal Power Act'' for mitigating impacts attributable to the Rule.

The Commission, on May 29, 1996, issued an order responding to EPA's referral. The Commission stated that:

> Given EPA's commitment to address air pollution issues, it is appropriate for EPA to seek assurances that if its best efforts are not successful, other agencies will examine their abilities to address the problem within the scope of their respective statutory authorities. Given the broad powers vested in EPA by the Clean Air Act, we fully expect EPA to succeed. We also note that if EPA is unable ultimately to address the issue, either through the voluntary OTAG process or by means of its authority under the Clean Air Act, we doubt that other agencies will be able to resolve the NO_X emissions problem under more limited authority. In such circumstances, action by the Congress may be necessary.
>
> Nevertheless, we believe that the Commission should be willing, if called upon under the circumstances EPA describes, to consider whether, under the Federal Power Act, it can and should attempt to address NO_X emissions issues attributable to the Rule. Therefore, if EPA concludes that the OTAG process has not succeeded in meeting its objectives in a timely manner, we will initiate a Notice of Inquiry to further examine what mitigation might be permissible and appropriate under the Federal Power Act. Such an inquiry would solicit public comment on how to assess appropriately the air pollution impacts attributable to the Final Rule, suitable ways in which to address such impacts, if any, and the scope of the Commission's authority to address such impacts.

[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.

Additionally, under the extraordinary circumstances in which EPA would undertake a Federal Implementation Plan, the Commission would agree to initiate contemporaneously a rulemaking to propose possible mitigation that could be undertaken by the Commission under the Federal Power Act. Such a rulemaking would be undertaken on the basis of the NOI mentioned above and would be appropriate only if environmental harm attributable to the rule that warranted mitigation is demonstrated. The Commission would rely upon information gleaned in the NOI in proposing possible mitigation strategies that are workable, tailored to address consequences attributable to the Rule, and consistent with our statutory authority. In no event would the Commission propose a mitigation strategy that would undermine the purposes of the rule to provide open transmission access on a non-discriminatory basis. We emphasize that neither the NOI nor the rulemaking, if they occur, will affect the implementation of the rule as required under Orders of the Commission. [850]

Thus, EPA has concluded that the Commission conducted an adequate analysis of the impacts of the Rule and agrees that the Rule is unlikely to have any significant adverse environmental impact in the near future. EPA also concurs that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This includes support for the efforts of OTAG to develop emissions reductions strategies. EPA will use its Clean Air Act authority to support completion of the OTAG process. EPA is prepared to establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans if states are unable or unwilling to act in a timely manner.

This commitment by EPA puts to rest the concerns expressed by those seeking rehearing on the issues of mitigation and disparate emissions standards. As stated in the FEIS:

The Ozone Transport Assessment Group (OTAG) represents [a] broad[] effort to deal with the interstate transport of pollutants that form ozone. OTAG is a voluntary organization that consists of 37 eastern states, the District of Columbia, and the EPA; industry and environmental groups also participate in the OTAG process. It was organized by the Environmental Council of States to study the transport of ozone and its precursors in the eastern U.S. and to develop mitigation strategies. OTAG is performing extensive photochemical grid modeling to determine ozone transport patterns and to evaluate the efficiency of various control strategies. OTAG intends to submit its findings regarding transport patterns and its recommendations for mitigation of ozone transport to EPA by January 1997.

OTAG is considering a number of strategies to mitigate the problem of ozone nonattainment. One strategy is the imposition of a cap and trading system for NO_X emissions in a 37-state area compromising the Northeast OTR and upwind states. If the cap and trading system becomes effective, it will fully mitigate any NO_X emissions increases attributable to open access transmission within the 37-state area, because increases within this area would have to be offset by a corresponding emission reduction.

The OTAG cap and trade program may not deal directly with emissions of pollutants other than NO_X. However, a cap on NO_X is likely to mitigate CO_2 and mercury increases, because internalizing costs of NO_X controls on coal-fired units is likely to dampen increases in capacity utilization of such units.[851]

The OTAG process includes the players of concern here—both the states from which alleged pollution increases would originate and the states that would be affected by the increased pollution. OTAG has a process underway to determine transport patterns and to evaluate control strategies. One strategy that is being considered is the imposition of a cap and trade system for NO_X emissions like that sought on rehearing here.[852] OTAG originally intended to submit its findings regarding transport patterns and recommendations for mitigation to EPA by January 1997. As a result of its decision to conduct additional modeling to determine the appropriate geographic applicability of emission reduction strategies, OTAG has extended its January timeframe by a few months, and now intends to complete its process by April or May 1997.

While OTAG is continuing its efforts, EPA is moving rapidly forward to remedy in a comprehensive fashion the interstate transport of air pollution. On January 10, 1997, EPA issued a notice of intent to use the authority granted it by sections 110(k)(5) and 110(a)(2)(D) of the Clean Air Act to require states to submit state implementation plan (SIP) measures to ensure that emission reductions are achieved as needed to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. This notice ''announces EPA's intention to conduct the formal process for implementing the regional reductions in ozone precursors that are necessary for areas in the Eastern United States to reach attainment.'' [853] EPA states that it intends to publish a Notice of Proposed Rulemaking in March 1997 that ''will propose overall amounts or ranges of NO_X and/or VOC emission reductions that each State would need to achieve to reduce the boundary condition concentrations of ozone and its precursors within a specified timeframe and require the submission of SIP controls to achieve these reductions.'' [854] The notice of inquiry also states that the SIP revision must contain a schedule for adoption and implementation of these measures. It notes that while EPA could allow up to 18 months for SIP submittals under section 110(k)(5), ''EPA is considering a more accelerated schedule for submittals under this SIP call to attain air quality benefits sooner and to facilitate area specific SIP planning.'' [855] EPA notes that as it goes through the process of developing an implementation program for the new standard, it will be able to take advantage of the information gathered by OTAG and account for emission reductions that result from the recommended strategy. EPA intends to publish the final SIP call notice in summer 1997.

Thus, actions to address the concerns with regard to mitigation and emissions standards disparity are taking place at this time and should be in place in the near future. This lays to rest as well concerns that any near-term impacts of the Rule have not been taken into account.

The Commission's Authority to Mitigate. The PA Com makes an unsupported assertion that the FPA's public interest standard authorizes the Commission to take mitigation measures related to its regulatory actions, and that the Commission should use the results of the OTAG process to develop a mitigation strategy.

The Joint Commenters argue that the Commission has broad authority under NEPA to mitigate the environmental consequences of its proposed actions. It contends that NEPA broadens the Commission's FPA authority—that NEPA policies and goals inform and expand the FPA's definition of the public interest. It also argues that the Commission's duty to ensure just and reasonable rates that are not unduly discriminatory or preferential also

[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).

[854] *Id.* at 1423.

[855] *Id.*

encompasses non-economic factors in appropriate circumstances.

The Joint Commenters conclude that, while it may be reasonable for the Commission to reject specific proposed mitigation measures, the Commission should, at a minimum, acknowledge that the FEIS demonstrates that the exercise of that authority is not warranted in this case. The Joint Commenters add that the Commission should initiate a rulemaking proceeding that considers mitigation options and evaluates the effectiveness of alternative strategies and proposals. The Joint Commenters concur that EPA's commitment to address air pollution issues is reasonable, but would have the Commission develop a backup NO_X mitigation mechanism by the end of 1996.

Thus, the PA Com and the Joint Commenters would have the Commission revisit in this order, by means of a generalized reexamination of the Commission's authority to impose mitigation, the conclusion in Order No. 888 that the mitigation measures recommended by commenters are beyond our authority to implement.

Order No. 888 and the FEIS fully examine the need for mitigation and the Commission's legal authority to impose mitigation measures. That examination led to the conclusion that: (1) the insistence of certain commenters that the Commission adopt and implement mitigation measures is based on significantly overstated assumptions regarding the contribution of the Rule to existing environmental problems, and that these assumptions about the impact of the Rule are wrong; (2) the existence for many years of a significant ozone nonattainment problem in part of the U.S. has led to the development of mechanisms to address this issue; (3) the mitigation recommendations suggested by commenters suffer from serious legal and practical shortcomings; and (4) the mitigation measures recommended by commenters are beyond the Commission's authority to implement and strong policy considerations militate against their adoption.

The PA Com and Joint Commenters have not raised any arguments that warrant revisiting the Commission's exhaustive examination of this issue in Order No. 888 and the FEIS, and we hereby reaffirm those decisions. We note in this regard that the PA Com did not advance a specific mitigation proposal in comments on the EIS and does not challenge the Commission's rejection in Order No. 888 of specific mitigation proposals advanced by other commenters. The Joint Commenters did propose a specific mitigation strategy which the Commission rejected because, among other things, it would have the Commission impose a revenue collection measure. The Joint Commenters do not challenge the Commission's analysis of its proposal or seek rehearing of its rejection. Instead, the Joint Commenters seek an acknowledgement from the Commission that, given the conclusions in the FEIS, the exercise of authority to mitigate is not warranted in this case. As we stated in Order No. 888 and the FEIS, mitigation is not warranted given the conclusions reached in the FEIS. The Commission also notes that we have thoroughly examined our legal authority in Order No. 888 and we find nothing in the arguments on rehearing that persuade us now to a different result. We have agreed to further examine our authority to engage in environmental mitigation through a Notice of Inquiry if EPA determines that the OTAG efforts are not successful. Therefore, it is unnecessary in this context to opine further in the abstract as to the scope of the Commission's mitigation authority.

Because the PA Com and the Joint Commenters have raised no new arguments that were not thoroughly addressed in Order No. 888 and the FEIS, it is unnecessary to repeat here the thorough analysis of this issue set forth in those documents. The Commission declines to grant rehearing on this issue.

Other Mitigation-Related Issues. VT DPS states that the Commission has given inadequate consideration to the possibility that the Rule may unnecessarily exacerbate environmental impacts and that the Commission, therefore, should adopt mitigation.

This statement, which VT DPS fails to substantiate, is incorrect. The FEIS and the process which led to the conclusions contained therein fully consider the environmental impact of the Rule. VT DPS fails to identify any particulars in which the FEIS is deficient. VT DPS's disagreement appears to be a generalized dissatisfaction with the substantive conclusion reached by the FEIS that the Rule will not have significant environmental impacts.

VT DPS next claims that the Commission's environmental review process has not facilitated the ability of affected parties to review all of the modeling assumptions. It also claims that other environmental reviews suggest that the Rule will have more serious NO_X emissions consequences than acknowledged by the Commission.

VT DPS again attacks the FEIS with a broad brush, but fails to identify ways in which the ability of parties to review modeling assumptions has been impeded. Likewise, it does not identify areas in which modeling assumptions have not been identified or any way in which its understanding of the FEIS has been hampered by the alleged unavailability of certain modeling assumptions. VT DPS is very late in raising such claims. The time to raise such issues is during the scoping process or in comments on the DEIS.

It is unclear what other environmental reviews VT DPS is referring to or the ways in which those reviews allegedly suggest that the Rule will have more serious NO_X emissions consequences than acknowledged by the Commission. Even if the unidentified studies reach different results than the FEIS this does not invalidate the conclusions contained in the FEIS. The mere fact of disagreement, even disagreement among experts in a given area, does not invalidate a study. [856]

VT DPS next recommends that the Commission establish an ongoing monitoring program in consultation with environmental agencies. It states that a monitoring program would allow the Commission to take timely action to mitigate any unintended consequences of the Rule.

An EIS is required to be prepared, when appropriate, prior to agency action. As the Supreme Court has stated, the moment at which an agency must have a final statement ready is the time at which it makes a recommendation or report on a proposal for federal action. [857] There is no requirement that an agency continue to evaluate the environmental impacts of a project after it is implemented, particularly where, as here, the agency has determined that the proposal is not likely to have adverse environmental impacts.

Moreover, as discussed extensively above, EPA's commitment to take action with regard to the underlying problems of the interstate transport of air pollutants provides a fuller measure of relief than that sought by VT DPS.

The New York Attorney General claims that it is essential that FERC exercise any authority it may have to mitigate the environmental effects of the Rule because Congress has limited EPA's authority in this regard. The Attorney General also claims that EPA's proposal in its comments of February 20, 1996 on the DEIS to place a cap on NO_X emissions would mitigate the effects of the Rule; it suggests basing

[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).

this system on the MOU. The Attorney General urges implementation of this system on the federal level pursuant to authority residing in EPA and/or FERC.

We note first that Congress has made a full grant of authority to EPA to address the issue of the interstate transport of air pollution. As discussed extensively above, EPA has committed to address this issue, and to use its authority pursuant to the Clean Air Act if states are unwilling to address this issue cooperatively through the MOU process. Thus, EPA has committed to undertake the relief sought by the Attorney General. If EPA is unsuccessful, the Commission has pledged to assist in this effort as discussed above.

D. Emissions Standards Disparity

Order No. 888 addresses claims that the Commission should ''level the playing field'' as to environmental standards. The argument was that unless the Commission imposes mitigation, competitors with ''dirty'' generation will be favored over ''clean'' competitors. Those urging the adoption of measures to level the playing field argue that mitigation of environmental impacts has a direct relationship to ensuring that open access is implemented under terms of economic fairness for all utilities, and not merely those with current low-cost regulatory advantages.

We responded to those arguments in Order No. 888 by noting that:

[A]ll power generation technologies have different costs. For example, hydroelectric facilities which, like coal-fired facilities, may have environmental mitigation conditions imposed on them, may be quite expensive to build compared to gas or oil-fired generation, but their operating costs may be significantly lower. These cost differences may reflect the different costs of complying with mandated environmental requirements; the prudent costs of complying with such mandates may be reflected in rates.

Indeed, sellers come to the power markets with a variety of advantages and disadvantages, many of which are the result of federal laws—for example, tax preferences, labor standards, and similar matters. In empowering the Commission to remedy undue discrimination and promote competition, Congress has not authorized the Commission to equalize the environmental costs of electricity production in order to ensure ''economic fairness.'' Such homogenization of competitors, or their costs, has never been a goal of the FPA.

* * * * *

In short, the ''economic nexus'' urged by commenters advocating that the Commission undertake to regulate air emissions is inconsistent with the ''charge to promote the orderly production of plentiful supplies of electric energy'' envisioned by the FPA.

We have exercised conditioning authority in the past only where necessary to ensure that jurisdictional transactions and rates do not result in anti-competitive effects, or are not unjust, unreasonable or unduly discriminatory or preferential. Thus, the conditions we have imposed have involved economic regulatory matters within our purview under the FPA. Any exercise of conditioning authority must, as the Supreme Court noted in *NAACP*, be directly related to our economic regulation responsibilities; EPA and the other commenters have not demonstrated such a nexus.

This distinction is more evident when one considers the way in which we are authorized to treat the costs of environmental compliance. There are legitimate costs of environmental compliance that should be reflected in jurisdictional rates to the extent prudently incurred, just as the prudent costs of complying with, for example, occupational health and safety requirements designed to protect utility employees should be reflected in jurisdictional rates. This we are authorized to do and we routinely review and allow such costs. However, the fact that the costs of providing utility workers with a safe workplace are properly reflected in utilities' jurisdictional rates does not mean that we have authority to condition sellers' rates or customers' use of jurisdictional services on meeting safety regulations that are in the public interest. The same rationale applies to environmental matters related to the rule. [858]

Rehearing Requests

Pennsylvania PUC. The PA Com asserts that the FEIS does not adequately address challenges posed by the Clean Air Act Amendments of 1990. The PA Com contends that the Rule may shift power production from Pennsylvania plants with strong environmental controls to upwind plants with less stringent controls, and that prevailing climatic patterns may transport the increased pollution downwind. It states that mitigation is needed to prevent degradation of downwind air quality and the imposition of further costs and limits on downwind generation.

The PA Com states that the Clean Air Act Amendments imposed stringent emission standards on Pennsylvania generation, but did not impose similar standards on neighboring states such as Ohio and West Virginia. It claims that the FEIS does not sufficiently consider these requirements. The PA Com concludes that implementing open access without mitigation will place Pennsylvania utilities at a competitive disadvantage, and that this result is inconsistent with the public policy goals of the Clean Air Act and the Federal Power Act. The PA Com also asserts that the Rule may discriminate against Pennsylvania utilities and the Pennsylvania coal industry, and that the combination of the Clean Air Act and Order No. 888 places Pennsylvania at a disadvantage in the competition for new industry and jobs.

The PA Com claims that Order No. 888 may push states in the Northeast Ozone Transport Commission into repudiating the existing MOU. It claims that it is inconsistent for one federal purpose which is statutorily clear (*i.e.*, clean air mandates established by the Clean Air Act Amendments) to be prejudiced by another federal purpose with only inferential statutory authority (*i.e.*, open access under sections 205 and 206 of the FPA).

The PA Com asserts in this regard that Phase II of the MOU will require by 1999 a 55 percent reduction in NO_X emissions in most of Pennsylvania and 65 percent (0.2 lbs/mmBTU) in the Philadelphia area. Title I of the Clean Air Act requires that the Northeast make reasonable progress towards attainment. If the inner zone of states comprising the Ozone Transport Commission do not achieve attainment, Phase III of the MOU will be implemented in 2003. Phase III requires a 75 percent reduction in emissions (0.15 lbs/mmBTU) for the entire state. According to the PA Com, to meet Phase III requirements most Pennsylvania coal-fired stations will have to install Selective Catalytic Reduction technology at a capital cost of $2.3 to $3.5 billion. It states that other Northeast states will be required to make expenditures that are much lower, and that states such as West Virginia and Ohio will not be subject to these requirements at all.

New Jersey BPU. The NJ BPU poses a similar concern. It states that upwind power plants are designed to meet NO_X emission standards which are substantially less restrictive than those required in New Jersey. The NJ BPU claims that this will have a two-fold impact—New Jersey air quality will be degraded through air transport and New Jersey utilities will be placed at a

[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. * * *

significant cost disadvantage. The NJ BPU states that it is inconsistent to assert substantial incremental benefits associated with competition brought about by the Rule, while asserting that the Rule will not result in any change in the utilization of existing power plants.

NJ BPU asserts that there are disparities in the electric industry among suppliers with regard to environmental impacts and costs, and that the Commission did not take this into account in determining the total economic benefit of a competitive wholesale generation market. It notes that the Commission may consider that it produced an economic benefit if the Rule enables a buyer in the Southeast to displace self-generated 4-cent power with 3-cent power from the Midwest. The NJ BPU contends, however, that if emissions from the plants producing the electricity result in 1.5 cents worth of mitigation costs on a downwind state, an appropriate economic analysis would conclude that the transaction actually increases total costs. NJ BPU asserts that it was inappropriate for the Commission to focus on economic gains while leaving cost issues to be dealt with by other entities.

NJ BPU recommends that the Commission adopt an integrated environmental, economic and energy policy approach which embraces the underlying principles in EPA's acid rain program. It states that the Commission should call for specific, significant and enforceable reductions in NO_X emissions coupled with a market based trading program of emissions. It asserts that this approach would ensure a fair and competitive playing field at a fraction of the expected cost savings from the Rule.

Joint Commenters. The Joint Commenters assert that the Commission has a duty under the FPA to mitigate undue preferences that affect competition in the wholesale power market. It concludes that this mandate must be applied here where implementation of open access policies without concurrent environmental mitigation will cause generation-owning utilities to face a discriminatory competitive situation.

The Joint Commenters note that the Northeast is an ozone nonattainment area because of high levels of ambient ozone pollution, and is therefore subject to strict NO_X reduction requirements. It states that regional utilities have invested significant sums in pollution reduction facilities and cleaner generation to meet legal requirements to reduce emissions. It contends that these utilities will be subject to additional NO_X reduction requirements, thus increasing generation costs, if ambient ozone levels increase as a result of competition.

The Joint Commenters contend that if open access increases emissions, utilities in the Northeast that have increased their generation costs to reduce air pollution will be required to bear additional costs to offset the impacts of increased upwind emissions. It states that the cost to Northeast utilities to offset additional NO_X emissions will likely be substantially higher than the costs would be to upwind competitors to mitigate emissions at the source. It claims that offsetting the impacts of a 250,000 ton NO_X increase in downwind nonattainment areas, where marginal NO_X and volatile organic compound (VOC) control costs average about $3,800 per ton, could total $1 billion. On the other hand, mitigating the pollution increases at generation sources which currently operate with minimal environmental controls would cost about $500 per ton, or $130 million. The Joint Commenters assert that this cost differential will be hidden from the competitive market because Northeast generators will bear the cost.

The Joint Commenters assert that this demonstrates that the wholesale bulk power market in the eastern United States is suffused with an existing undue preference that inordinately favors one category of competitors by allowing them to produce and sell power at a lower marginal cost. This preference exists today as a result of costs incurred in the past to meet Clean Air Act obligations; the FEIS demonstrates that Order No. 888 could worsen this situation as a result of increased sales from older, higher-emitting upwind coal generators.

The Joint Commenters add that, aside from the competitive unfairness of this situation, the undue preferences will produce inefficiencies which distort investment decisions and increase the overall cost to produce electricity—the antithesis of what Order No. 888 is meant to achieve. It asserts that these inefficiencies will occur in four ways:

Sources in downwind nonattainment areas could have to spend hundreds of millions of dollars to address increased air pollution resulting from open access if polluting plants do not mitigate at the source. Thus, less efficient investments will be made to reduce air pollution and the overall cost of generating electricity will be higher than in a competitive market that is not distorted by discrimination.

Order No. 888 could adversely impact the economic dispatch of generating sources under competitive conditions. In the absence of mitigation, generation from higher polluting upwind plants could displace generation from plants in the Northeast that operate more efficiently at the margin. As utilities in the Northeast are required to add more costly emission controls in response to interregional migration of air pollution, their operating costs will be driven up and may exceed the costs of less efficient plants which have avoided such controls. Thus, in the absence of mitigation, Order No. 888 may foster less efficient utilization of generating resources.

Implementation of Order No. 888 without mitigation may distort the market for future generation capacity. If older, more highly-polluting plants can shift the environmental cost of production to other wholesale generators, they are likely to expand their output to address market needs, thus reducing the demand for more efficient, clean-burning generating facilities.

Transmission from the Midwest to the East is often heavily constrained. Consequently, a distorted price signal to increase generation in the Midwest would exacerbate existing constraints and improperly stimulate the construction of new transmission capacity to support additional interregional transactions.

The Joint Commenters conclude that the Commission has an obligation to exercise its authority in non-arbitrary manner, particularly when acting to prevent undue discrimination.

Finally, the Joint Commenters disagree with the Commission's response to this issue in Order No. 888. It asserts that the Commission and the courts have found in the "price squeeze" context that the Commission has authority to remedy anti-competitive discrimination, even when it is caused by regulatory practices of others over which it and its regulated public utilities have no control. Second, the Commission has the authority and responsibility to address environmental issues that directly affect and have a nexus to its section 205 and 206 responsibilities. Third, if the competitive market that the Commission wishes to create will not operate fairly or efficiently, the Commission has a duty to consider whether it should go forward at all if it believes it does not have the power to remedy important adverse competitive consequences.

Commission Conclusion

Congress has empowered the Commission to remedy undue discrimination and promote competition; it has not authorized the Commission to equalize the environmental costs of electricity production in order to ensure "economic fairness." Homogenization of competitors, or their costs, has never been a goal of the FPA.

Action in Order No. 888 to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce does not require action by the Commission to cure all competitive differences between participants in the utility marketplace. This is particularly true where the disparities arise because Congress has established policies with regard to competing issues of national significance and charged other agencies of the federal government with implementing those policies. The assertion that the Commission must eliminate any competitive disadvantage arising from congressionally mandated policies, including the vital national policies set forth in the Clean Air Act, before it can act to remedy undue discrimination and encourage competition in the electric utility industry is in error.

Furthermore, as noted above, the analysis reflected in the FEIS refutes the claim that the Rule will result in significant environmental impacts. Thus, there is no basis in any event to support requests that the Commission ''level'' the playing field.

Recounted briefly, those findings show that, without the Rule, NO_X emissions are expected to decline until at least the year 2000. Thereafter, again without the Rule, NO_X emissions are expected to increase steadily through the year 2010. The extent of the decrease and increase will be largely determined by the relative prices of natural gas and coal.

The analysis also demonstrates that the Rule will not in any significant respect affect these overall trends. The analysis shows that if the Rule results in efficiency gains in the electric industry that favors the use of natural gas as a fuel, the effect will be slightly beneficial; total NO_X emissions will be reduced overall by about two percent nationwide below what would otherwise be expected to occur. If the Rule results in efficiency gains that favor the use of coal as a fuel, the Rule is expected to increase NO_X emissions approximately one percent above what would otherwise be expected to occur.

Even analyzing the highly unlikely frozen efficiency case, the analysis demonstrates that the impacts of the Rule will not be great and will not vary significantly from those projected by staff under the assumptions discussed above. This study, utilizing a combination of assumptions geared to demonstrate the greatest impact the Rule might have on increased NO_X emissions, produced little in the way of environmental consequences associated with the Rule. Under these extreme (and unlikely) conditions, there would still be a net decrease in NO_X emissions until at least the year 2000, albeit a smaller decrease than in the base cases. Comparing projections of emissions for the same years, emissions would be higher than the base cases only by two percent in 2000 and three percent in 2005. It is only in the year 2010, assuming these improbable scenarios, that NO_X emissions associated with the Rule would be higher than the base case by even five percent.

All told, this analysis demonstrates that the Rule will affect air quality slightly, if at all, and that the environmental impacts are as likely to be beneficial as negative. This is true under scenarios contrived to maximize emissions under circumstances that the Commission believes to be highly unlikely. This is also true in the near to mid-term. Assuming that any environmental impacts occur, they are years in the future and may well be beneficial.

Thus, contrary to the position taken by those seeking to have the Commission impose mitigation, the Rule will not result in impacts requiring mitigation to level the playing field.

Moreover, as also noted above, EPA has committed to address the existing NO_X transport issue, including the contribution of the Rule, if any, to those impacts. It must be emphasized in this regard that the Northeast has experienced significant air pollution problems for many, many years. Much of this pollution is generated by activities within the affected states and within the affected region; the problem is exacerbated somewhat by the airborne transport of pollutants from upwind areas, including pollutants resulting from the generation of electricity that will occur regardless of any future increase in generation that might result from implementation of the Rule.

Put differently, the pollution problems in the individual states and in the Northeast in general result primarily from economic activities within those states. The airborne transport of pollutants, including pollution resulting from existing electric generation, adds to the existing problem to some degree. The analysis in the FEIS demonstrates that open access may increase the amount of upwind generation by some small increment, and thus increase the downwind NO_X levels by an even smaller incremental amount. On the other hand, depending on the future competitive position of natural gas versus coal, a situation over which the Commission has no control, the Rule may decrease the amount of pollution that would otherwise exist and thus decrease downwind pollution. In any event, the Rule will affect existing trends slightly, if at all.

In recognition of the situation described above, which again is likely to be affected only very slightly, if at all, by the Rule, EPA has committed to address the overall issue of NO_X emissions as part of a comprehensive program developed by EPA and the states. EPA has committed to use its authority under the Clean Air Act to successfully complete the OTAG process. EPA states that it will, if necessary, establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans if some states are unable or unwilling to act in a timely manner.

As discussed in the FEIS, and as noted above, OTAG has efforts underway to develop responses to this problem. For example, OTAG intends to submit its findings regarding ozone transport patterns and its recommendations for mitigation of ozone transport to EPA by April or May 1997. If this process is less than fully successful, the Clean Air Act authorizes EPA to act in a relatively short time-frame to address this problem. EPA has committed to exercise this authority to address the problem.

It must be emphasized that EPA has stated its intent to address the problem regardless of the effects of the Rule. Even if the Rule results in environmental impacts, those incremental impacts will be addressed as part of the comprehensive NO_X regulatory developed by EPA in conjunction with the states.

Thus, EPA has committed to undertake the mitigation sought by the PA Com, NJ BPU and Joint Commenters. The Commission has stated its intent to participate in this process as discussed above. This result negates claims that implementing open access without mitigation will place downwind utilities and the Pennsylvania coal industry at a competitive disadvantage. Accordingly, the requests that the Commission impose mitigation measures to ''level'' the environmental playing field are denied.

E. Short-Term Consequences of the Rule

The FEIS projects future electric powerplant emissions under a range of assumptions without the Rule (base cases). These results are then compared to what electric powerplant emissions are likely to be under corresponding assumptions with the Rule in place (Rule scenarios). The study utilizes three reporting years: 2000, 2005, and 2010. These reporting years were chosen because they cover a reasonable time frame for the study. Beyond 2010, the projections are dependent on too many unforeseeable factors to be meaningful.[859]

Although the effects of the Rule will begin to occur when the final Rule is issued, the effects should develop gradually over time. Measurable effects are expected to be clearly observable by the year 2000, though not necessarily fully complete.[860]

The FEIS analysis of the Rule scenarios shows that NO_X emissions are expected to decrease significantly between 1993 and 2000. The Competition-Favors-Gas Scenario demonstrates that the Rule will reinforce decreases already present in the base case. Thus, the Rule will enhance underlying environmental improvements. While the Competition-Favors-Coal Scenario demonstrates small emissions increases, NO_X emissions nonetheless continue to decrease from 1993 to 2000. A similar trend is also seen on a regional basis. The Rule does not alter the basic pattern of environmental improvement.[861]

Rehearing Requests

New Jersey BPU. The NJ BPU claims that the FEIS fails to recognize possible short-term effects the Rule may have on existing ozone problems in the Northeast, and that the failure to address short-term consequences is of particular importance to nonattainment states who must meet Clean Air Act attainment dates in 1996 and 1999.

Joint Commenters. The Joint Commenters claim that by examining the period between 2000 and 2010, the FEIS fails to analyze near-term impacts and the need for a short-term mitigation strategy. Joint Commenters note that the Rule will be implemented almost immediately, and that changes in generation plant utilization that give rise to the greatest environmental concerns may occur very quickly.

The Joint Commenters are concerned that the FEIS does not consider how projected environmental effects prior to 2000 would impact air quality and Clean Air Act attainment deadlines. The Joint Commenters contest the conclusion that utility NO_X emissions will decline between 1993 and 2000. It states that emissions will increase each year between 1993 and 2000 except in 1996 and 2000, when large NO_X reductions will be implemented pursuant to the Clean Air Act. The Joint Commenters also contend that it is irrelevant whether clean air programs will cause overall emissions to be lower in 2000 than they were in 1993; the relevant question is whether emissions will be higher with Order No. 888 than without it.

The Joint Commenters contend that the data presented in the FEIS for the year 2000 suggest that, if the Rule is considered in isolation, there will be potentially significant short-term emissions increases in the period 1996–2000. It states that the FEIS indicates that implementation of the Rule under the Competition-Favors-Coal Scenario with expanded transmission will lead to an additional 132,000 tons of NO_X emissions in 2000 compared with the frozen efficiency reference case. It contends, assuming a linear increase, that this means there could be an additional 75,000, 94,000 and 113,000 tons of NO_X emissions as a result of the Rule in 1997, 1998, and 1999, respectively.

Commission Conclusion

The Joint Commenters' claims that implementation of the Rule will lead to an additional 132,000 tons of NO_X emissions in the year 2000 in incorrect. As is the case with regard to its assertion above that the Rule will result an additional 315,000 tons of NO_X emissions in 2010, this impact was derived by selectively choosing numbers from the FEIS, comparing two sensitivity cases designed to be unrealistically low and high extremes. The low emissions case is the frozen efficiency case that represents a complete reversal of current industry and regulatory trends that are occurring without the Rule. The high emissions case represents an increase in transmission capacity that cannot reasonably be ascribed to the Rule. As stated in the FEIS, these cases were selected to examine the sensitivity of FEIS findings to certain extreme assumptions maintained by commenters and are not the appropriate cases for determining potential environmental impacts from the Rule.

Moreover, we note that the Joint Commenters reference increases from the Rule without noting equally likely decreases. Even with the lower emissions resulting from the unrealistic frozen efficiency case, the FEIS finds decreases in emissions from the Rule when competitive forces lead to greater efficiency for natural gas generation compared to coal.

The Commission has analyzed the Rule and found that its impacts will be insignificant. We also note that even if the Rule were to result in short-term emission increases, EPA has signaled its willingness to address the transport of pollutants in a timely fashion. As discussed above, EPA has concluded that any emissions increases associated with the Rule should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This approach includes support for OTAG efforts to develop emissions reduction strategies. OTAG plans to submit its findings and mitigation recommendations to EPA by April or May 1997. As discussed above, EPA has issued a notice of intent to adopt by summer 1997 a rule that would require state implementation plan measures to ensure that emission reductions are achieved as needed to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. EPA is contemplating establishing deadlines for state implementation plan submittals ranging from six months to 18 months following the date of publication of its notice of final rulemaking.

The instant Rule will affect the existing NO_X transport issue very little, if at all. As stated in Order No. 888, the Rule is not the appropriate vehicle for resolving this debate. The appropriate regulatory mechanism for addressing the overall NO_X problem, including emissions from electric utility generating plants, is a NO_X emissions cap and allowance trading scheme along the lines of that developed by the Congress under the Clean Air Act for SO_2 emissions. As noted, EPA has committed to implement this approach. Even if there are slight environmental impacts associated with the Rule, they are better and more effectively addressed as part of a comprehensive NO_X regulatory program.

G. Cost Benefit Analysis

''The legal and policy cornerstone'' of Order No. 888 ''is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce.'' [862] As reiterated in the FEIS, the purpose of the Rule is to increase access to non-discriminatory transmission services and thereby increase competition in wholesale electric markets.[863]

The FEIS states that the Rule will give wholesale power customers a greater opportunity to obtain competitively priced electricity. Competition will create benefits through better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion.

[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.

[863] FEIS at ES–13 through ES–16.

Only the first—better use of existing assets and institutions—was estimated quantitatively: approximately $3.8 to $5.4 billion per year. The FEIS also discusses other benefits that cannot be quantified but may be large. Based on the experience of, for example, the natural gas and telecommunications industries, the Commission opined that the other three are likely to increase industry efficiency—and benefits—substantially.[864]

As described elsewhere in this order, the FEIS also discusses extensively possible environmental effects (*i.e.*, costs) of the Rule. It concludes that the Rule could raise or lower national emissions slightly, but will not have a significant effect on the environment.

Rehearing Requests

The Joint Commenters contend that the analysis of projected benefits from the Rule appears to be inadequately substantiated and uses assumptions that are inconsistent with those used to reach a finding of no significant impact on environmental issues. Although Joint Commenters do not challenge the conclusion that Order No. 888 will result in economic benefits, it states that the benefits identified in the FEIS are inadequately substantiated and do not reflect a balanced analysis. It claims that courts have held that when economic development is the selling point or raison d'etre of an action NEPA requires the agency to provide a specific comparison of economic benefits versus environmental costs. It concludes that the analysis of the economic benefits of Order No. 888 is tipped in favor of benefits, especially when contrasted with the analysis of projected environmental impacts.

Joint Commenters state that the conclusion that benefits will range from $3.76 to $5.37 billion per year is not properly documented and cannot be relied upon as justification for implementing the Rule without mitigation. It contends that the Commission is counting benefits from changes that are unrelated to the Rule, such as benefits resulting from higher plant availability factors. Joint Commenters claim that this assertion appears to be inconsistent with industry reactions to competition to date. The same is true of planning reserve margins. It states that key assumptions used to define the operating savings, particularly fuel price assumptions, are unreasonable. It adds that these savings are the ones that give rise to adverse environmental effects due to increased utilization of existing low-cost coal generation. Therefore, it is inappropriate to count these economic benefits without examining the offsetting environmental costs, which increase as the level of the asserted benefits increase.

Finally, Joint Commenters assert that the FEIS does not address potential costs associated with implementing the Rule. These include costs to the Northeast and other regions of additional environmental compliance and the impact on public health of additional pollution; socioeconomic costs associated with utility downsizing; potential adverse effects on nuclear power plant operations from competition; or potential regulatory costs associated with compliance with Order No. 888. Thus, Joint Commenters conclude that the FEIS does not provide a basis for calculating the net benefits of Order No. 888. It also states that the FEIS does not provide a basis for concluding that the potential savings will exceed the additional costs associated with increased use of coal generation without mitigation.

Commission Conclusion

The fulcrum of Joint Commenters' challenge is its claim that when economic development is the selling point of a proposed action, NEPA requires the agency to provide a specific comparison of economic benefits versus environmental costs. The Joint Commenters do not challenge the conclusion that the Rule will result in economic benefits. Rather, it claims that the benefits identified in the FEIS are not adequately substantiated and do not reflect a balanced analysis of benefits versus costs. This argument is made to further the claim, asserted by Joint Commenters in various forms, that the Commission must impose mitigation to ''level'' the playing field.

The Joint Commenters' argument misapprehends the purpose of Order No. 888, the role a cost-benefit analysis plays in an EIS, and the reasons for the Commission's discussion of the economic benefits of the Rule.

The purpose of the Rule is not to foster economic development, although the Commission anticipates that this will be a salutary effect of open access. The purpose of the Rule is to promote competition in the wholesale bulk power markets by remedying undue discrimination in access. The fact that the Rule will create benefits through better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion is a consequence rather than the purpose of the Rule.

The Joint Commenters also mistake the role a cost-benefit analysis plays in an EIS. The CEQ regulations implementing NEPA set forth the requirements pertaining to a cost-benefit analysis at 40 CFR 1502.23 (1996):

> If a cost-benefit analysis relevant to the choice among environmentally different alternatives is being considered for the proposed action, it shall be incorporated by reference or appended to the statement as an aid in evaluating the environmental consequences. To assess the adequacy of compliance with section 102(2)(B) of the Act the statement shall, when a cost-benefit analysis is prepared, discuss the relationship between that analysis and any analyses of unquantified environmental impacts, values, and amenities. For purposes of complying with the Act, the weighing of the merits and drawback of the various alternatives need not be displayed in a monetary cost-benefit analysis and should not be when there are important qualitative considerations. In any event, an environmental impact statement should at least indicate those considerations, including factors not related to environmental quality, which are likely to be relevant and important to a decision.

Thus, the function of a cost-benefit analysis is to assist in the choice among environmentally different alternatives. As discussed above, the Commission's recitation in the FEIS of the anticipated economic benefits of the Rule is not undertaken to assist in the choice among environmental different alternatives. The FEIS discusses the expected economic benefits of the Rule in a broader context, noting that ''[t]he most important socioeconomic effect of the proposed rule is expected to be potentially large benefits to ratepayers and to the economy as a whole.'' [865]

The authorities cited by the Joint Commenters do not alter this conclusion. The Commission is not using the benefits of the Rule as a selling point to go forward with the action while ignoring disadvantages that might flow from it. The FEIS fully examines the impacts of the Rule and concludes that implementation of the Rule will not result in adverse environmental consequences. The Joint Commenters disagreement is with this substantive conclusion, not with the alleged failure to conduct a cost-benefit analysis. Their disagreement does not mean, however, that the Commission has ignored the disadvantages that Joint Commenters assert would flow from the Rule. In brief, as discussed throughout the FEIS, Order No. 888, and this order on rehearing, the Commission has examined the impacts of the Rule and

[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.

concluded that it will not result in environmental harms.

Thus, even under the broadest possible interpretation of the cost-benefit analysis requirement, the Commission has evaluated the benefits of the Rule against its impacts and concluded that the benefits are likely to be significant and that the impacts are likely to be insignificant.[866]

The D.C. Circuit rejected the underlying argument advanced here by the Joint Commenters in *Public Utilities Commission of the State of California* v. *FERC*, 900 F.2d 269 (D.C. Cir. 1990). There, California contended that the Commission did not comply with NEPA in granting an Optional Expedited Certificate (OEC) permitting construction of a natural gas pipeline. California argued that the Commission could not have balanced the adverse environmental effects against the need for the project because under the OEC procedures it made no particularized inquiry into the economic benefits of the pipeline. The court responded that:

> Two of our cases speak of a NEPA requirement that ''responsible decisionmakers * * * fully advert[] to the environmental consequences'' of a proposed action and ''decide[] that the public benefits * * * outweigh[] the[] environmental costs.'' *Illinois Commerce Comm'n* v. *ICC*, 848 F.2d 1246, 1259 (D.C.Cir.1988); *Jones* v. *District of Columbia Redevelopment Land Agency*, 499 F.2d 502, 512 (D.C.Cir.1974). Though the Commission engaged in an ''individualized consideration and balancing of environmental factors,'' as required by *Calvert Cliffs' Coord. Comm.* v. *United States Atomic Energy Comm'n*, 449 F.2d 1109, 1115 (D.C.Cir.1971), its evaluation of the nonenvironmental aspects of the pipeline was not individualized. As to them the Commission stated that ''the interests of the public articulated in *our adoption of the optional certificate process* [i.e., Order No. 436] outweigh, on balance, the relatively insubstantial environmental harm which will result from a properly mitigated WyCal Pipeline.'' *Mojave Pipeline Co.,* 46 FERC at 61,168 (emphasis added).
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> California's insistence on a particularized assessment of non-environmental features finds no support in the statutory language. See NEPA § 102, 42 U.S.C. § 4332 (requiring the agency to consider a variety of environmental, not economic, factors). Its theory would disable any number of efforts at streamlining the resolution of regulatory issues that have nothing to do with the environment. An agency's primary duty under the NEPA is to ''take[] a 'hard look' at environmental consequences.'' *Kleppe* v. *Sierra Club*, 427 U.S. 390, 410 n. 21, 96 S.Ct. 2718, 2730 n. 21, 49 L.Ed.2d 576 (1976). We will not extend that statute well beyond its realm so as to create unnecessary conflicts with others. [867]

Thus, an agency need not conduct a particularized assessment of the nonenvironmental features of a proposal, in particular its economic benefits or costs. The Commission nonetheless examined the potential costs of the Rule and determined that those costs will be very small and may be positive instead of negative in any event. The Commission has also examined the benefits of the project and concluded that it will have substantial benefits. Accordingly, the request for rehearing is denied.

H. Socioeconomic Impacts

The FEIS examines the socioeconomic impacts of the Rule, including whether the Rule will result in regional shifts in economic activity (especially electric generation and coal mining).[868] The analysis demonstrates that an effect of a more competitive industry may be increased use of existing electric generating facilities. Consequently, it seems likely that those who supply fuel to existing plants could see a higher demand for their output as a result of the Rule. The FEIS notes that this might not be true in all places, however, if factors such as changes in environmental standards work in the opposite direction. The FEIS does not attempt to measure local or site-specific impacts given the speculative nature of such impacts.

The FEIS also notes that open access could lead to changes in employment patterns, but concludes that it is highly uncertain, however, which changes are likely to result from restructuring.[869] The FEIS notes that some changes should lead to cost reductions that will tend to increase jobs in other industries, as well as lower rates for other consumers. Lower power bills can make other industries more competitive and lead them to increase employment.

The FEIS also notes that the Rule is only part of the restructuring currently affecting the industry. Employment in traditional utilities has fallen in recent years. Developments at the state and federal levels will increase competition in the industry even without the Rule. Given the highly uncertain nature of future developments in the electric industry and the complex, dynamic economic issues involved, the FEIS concludes that any quantitative estimate of changes in employment (or even the direction of change) would be highly speculative.

Rehearing Requests

The PA Com claims that socioeconomic impacts that may result from regional economic shifts occurring as a result of the Rule are not adequately discussed in the FEIS. It states that Order No. 888 contemplates a reduction in the amount of coal-fired generation, and that if Pennsylvania generation is shut-down or dispatched less often in favor of generation that is not subject to the same environmental costs and requirements, less Pennsylvania coal will be mined.

The PA Com states that Pennsylvania produces 60 million tons of coal a year, most of which is purchased by Pennsylvania electric utilities. It alleges that the Pennsylvania coal industry provides 9,200 direct mining jobs and 9,500 support service jobs. Coal sales contribute $1.5 billion to the Pennsylvania economy each year and provide an annual payroll of $600 million. The PA Com adds that if coal production declines, the state may curtail efforts to reclaim abandoned mines and coal refuse piles.

The PA Com also contends that social obligations now borne by transmission owning utilities—demand side management programs, integrated resource planning, low-income assistance programs, and federal environmental mandates—have an impact upon price and the market for power, and that utilities might view these obligations as an impediment to competition. It claims that third parties who wish to use the transmission system may balk if they are required to contribute to those social goals.

Finally, the PA Com claims that functional unbundling, open access on a comparability basis, and increased competition may impact reliability of service. It states that it is concerned that reliability is subordinate to economic concerns, and that if reliability is not an articulated foundation of FERC actions, system reliability may suffer. It concludes that the FEIS assumes that reliability will be enhanced by open access, but that this assumption is not adequately explained.

Commission Conclusion

The PA Com's concerns as to the alleged socioeconomic impacts of the Rule are based on a series of tenuous economic ''what-ifs.'' It assumes that the Rule will result in a reduction in Pennsylvania generation. It assumes from this that less coal will be mined in

[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.

Pennsylvania and that Pennsylvania will suffer adverse economic consequences. It then assumes that this might lead Pennsylvania to curtail efforts to reclaim abandoned surface and strip mines. No basis has been shown to support the elements in this chain of assumptions. The effects Pennsylvania fears are simply too speculative to assess at this time.

Moreover, the PA Com's concerns stem from the postulated *economic* impacts of the Rule rather than from the alleged impact of the Rule on the *physical environment.* Thus, its concerns are not proper for consideration in an EIS. The CEQ states that socioeconomic impacts alone do not warrant study in an EIS.[870] The CEQ also states that an agency must make reasonable efforts in preparing an EIS to acquire relevant information concerning socioeconomic impacts when economic or social *and* natural or physical environmental effects are interrelated.[871] If such effects are not interrelated, they need not be considered. In this case, the PA Com's concerns stem from what it anticipates will be the economic impact of the Rule on Pennsylvania, and not from the natural or physical environmental impacts of the Rule. Thus, these concerns are not proper for consideration in an EIS.[872]

The approach to such issues is perhaps best symbolized by the Supreme Court's decision in *Metropolitan Edison Co.* v. *People Against Nuclear Energy,* 460 U.S. 766 (1983). In that case, People Against Nuclear Energy (PANE) contended that NEPA required the Nuclear Regulatory Commission to consider whether restarting the Three Mile Island-1 nuclear reactor after the accident at the Three Mile Island-2 reactor would ''cause both severe psychological health damage to persons living in the vicinity, and serious damage to the stability, cohesiveness, and well-being of the neighboring communities.'' [873] The court rejected this argument:

> The theme of § 102 is sounded by the adjective ''environmental'': NEPA does not require the agency to assess *every* impact or effect of its proposed action, but only the impact or effect on the environment. If we were to seize the word ''environmental'' out of its context and give it the broadest possible definition, the words ''adverse environmental effects'' might embrace virtually any consequence of a governmental action that someone thought ''adverse.'' But we think the context of the statute shows that Congress was talking about the physical environment—the world around us, so to speak. NEPA was designed to promote human welfare by alerting governmental actors to the effect of their proposed actions on the physical environment.
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> * * * Thus, although NEPA states its goals in sweeping terms of human health and welfare, those goals are *ends* that Congress has chosen to pursue by *means* of protecting the physical environment. [874]

Even though it was not incumbent upon it to do so, the Commission analyzed the concerns raised by the PA Com to the extent it was practicable to do so. The impacts of the Rule on future levels of coal-fired generation in Pennsylvania or on employment in a specific geographic area or in a specific economic sector are influenced by a virtually unlimited roster of other factors, and thus are too speculative to be useful.

I. Coastal Zone Management Act

Order No. 888 found that the Rule does not constitute a federal activity subject to compliance with the Coastal Zone Management Act, 16 U.S.C. § 1451 *et seq.* (CZMA).[875] Order No. 888 concluded that:

> Connecticut has in any event waived its right to request a consistency determination for the Commission's rulemaking. Connecticut's coastal management program's list of federal agency activities likely to require a consistency determination does not (for good reason) describe rulemakings of this kind, and the rule will not ''result in a significant change in air or water quality within the management area'' (the program's catch-all category). In addition, Connecticut did not notify the Commission of its conclusion that the Rule requires a consistency determination until well after 45 days from receipt of several notices of the rulemaking proceeding. Consequently, pursuant to 15 CFR 930.35(b), Connecticut has in any event waived its right to request a consistency determination for this rulemaking. [876]

Rehearing Requests

The Connecticut Department of Environmental Protection (Connecticut DEP) requests that the Commission determine whether Order No. 888 is a federal activity requiring a coastal consistency determination, determine whether the Rule is consistent with Connecticut's coastal management plan (CMP), and consider the impacts that promoting competition and altering transmission and generation patterns may have on water quality in the Long Island Sound. The Connecticut DEP also requests that the Commission mitigate potential increases in nitrogen and sulphur oxide emissions occurring as a result of the Rule.

Commission Conclusion

On August 20, 1996, the Commission responded to the Connecticut DEP, issuing a consistency determination and a negative determination. The response notes that the FEIS focuses on the concerns raised by the Connecticut DEP and concludes that the most important factor determining changes in future emissions is the relative competitive

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[870] 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).

[871] 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. * * *

[872] 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).

position (*e.g.,* price) of coal and natural gas. Depending on the relative prices of these fuels, emissions from electric generating facilities may increase slightly or decrease slightly. Regional effects, including those for the region encompassing Connecticut, are projected to be similar. The response also notes that these estimates fall within the ''noise'' level of the model. That is, they are smaller than the uncertainties in the science underlying the model.

Thus, the response concludes that the Rule will not have an effect on the land and water uses or natural resources of Connecticut. Accordingly, the Commission issued a negative determination pursuant to the regulations implementing the CZMA, 15 CFR 930.35(d). [877]

The response also notes that even if the Rule were to have a minimal effect on Connecticut's coastal zone, the Rule is consistent to the maximum extent practicable with the enforceable policies of the Connecticut Coastal Management Plan (Connecticut Plan). The Connecticut Coastal Management Act and supporting policies which provide the basis for the Connecticut Plan require that activities be consistent with the Clean Air Act. The Connecticut Plan provides that activities are not assumed to directly affect Connecticut, and thus do not require a consistency determination, unless they ''would result in a significant change in air or water quality.''

The August 20, 1996 response concludes that the Rule is consistent with the requirements of the Clean Air Act and will not result in a significant change in air or water quality in Connecticut. In fact, depending on the future prices of fuel, the Rule is equally likely to improve air quality over Connecticut and decrease emissions deposition in the waters of the Long Island Sound. Thus, the Rule is consistent with the Connecticut Plan regardless of any slight effects it may have.

Finally, the response notes that the action sought by Connecticut DEP to ensure consistency with the Connecticut Plan has already been taken in any event. Following issuance of the Rule, EPA, the federal agency charged with implementing the Clean Air Act, stated that it would use its authority to comprehensively address NO_X emissions, including any potential incremental increases in emissions that might result from implementation of the Rule, in the 37-state region that makes up the Ozone Transport Assessment Group. This region includes Connecticut. In an Order issued May 29, 1996, the Commission agreed to examine the issue of mitigation of the impacts, if any, of the Rule in the event that EPA and the OTAG states are unsuccessful in addressing the NO_X problem.

Thus, the FEIS demonstrates that the Rule will not have an effect on any land or water use or natural resource of Connecticut's coastal zone. Moreover, the Rule is consistent with Connecticut's CMP. Finally, EPA and the Commission have taken the action sought by Connecticut DEP to ensure consistency with Connecticut's CMP. These actions fully address Connecticut DEP's coastal zone concerns.

VI. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA) [878] requires rulemakings to either contain a description and analysis of the effect that the proposed or final rule will have on small entities or to contain a certification that the rule will not have a significant economic impact on a substantial number of small entities. In the Open Access and Stranded Cost Final Rules, the Commission certified that the final rules would not impose a significant economic impact on a substantial number of small entities.[879]

NRECA and SBA question this certification.[880] According to NRECA there are about 1,000 rural electric cooperatives and 2,000 municipal electric systems, most of which meet the RFA definition of small electric entity. NRECA states that the Commission has imposed open access, OASIS and code of conduct requirements on non-public utilities. NRECA maintains that if non-public utilities do not meet these requirements, ''they will not retain access over the long-term to the nation's bulk power transmission grid—access they must have if they wish to stay in business.'' [881]

NRECA also contends that the stranded cost issue will affect small non-public utilities ''any time a non-public utility is required to render reciprocal transmission service, and loses a customer as a result of rendering that service, or a TDU [transmission dependent utility] loses a customer to an open access public utility transmission provider.'' [882] NRECA asserts that both the OASIS Final Rule and the Capacity Reservation Tariff NOPR [883] will substantially burden small non-public utilities.[884] NRECA further maintains that the Commission's waiver provisions will not alleviate the burden on small utilities. It states that filing a waiver request with the Commission is burdensome for small utilities.

SBA states that 30 percent (50 of 166) of public utilities are small under the SBA's definition of a small public electric utility.[885] SBA contends that if, as the Commission has found, 11 percent of public utilities are small, the Final Rules will still affect a significant number of small public utilities.

SBA challenges the Commission's reliance on *Mid-Tex Electric Cooperative, Inc.* v. *FERC.*[886] It contends that the Commission should have analyzed the probable effect of the Final Rules on small businesses by projecting, perhaps on the model of the deregulated

[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.

[879] 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.

[881] NRECA at 42–43.

[882] NRECA at 44.

[883] 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*).

[884] 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*).

telecommunications industry, how many small electric utilities, as the SBA defines that term, would enter the deregulated electric utility market.

Commission Conclusion

A. Docket No. RM95–8–000 (Open Access Final Rule)

1. Public Utilities

In the Open Access Final Rule we determined that the Rule applies:

to public utilities that own, control or operate interstate transmission facilities, not to electric utilities per se. The total number of public utilities that, absent waiver, would have to have open access tariffs on file is 166. Of these, only 50 public utilities dispose of 4 million MWh or less per year. Eliminating those utilities that are affiliates of other utilities whose sales exceed 4 million MWh or less per year, or are not independently owned, the total number of public utilities affected by the Open Access Final Rule that qualify under the SBA's definition of small electric utility is 19 or 11 percent of the total number of public utilities that would have to have on file open access tariffs.[887]

We do not agree with the SBA that 11 percent of all of the public utilities that would have to file open access tariffs with us is a significant number. Also, the SBA has overlooked several of the other findings we made as to the possible effect of the Open Access Final Rule on small public utilities. As we noted, of the 19 public utilities that would come within the SBA's definition of small electric utility, five have already filed open access tariffs with the Commission, so that the effect of the Open Access Rule on these utilities should not be significant.[888]

Further, the Commission is specifying the non-rate terms and conditions of the tariffs that public utilities must file, so all public utilities need to do is file a rate, and the small public utilities with open access tariffs already on file with us need not even do that. They may elect to continue service under the Open Access Final Rule's non-rate terms and conditions at their existing rates. In our Final Rule we estimated that the cost for filing a rate would not, on average, exceed one half of one percent of total annual sales for small electric utilities,[889] which is not a significant economic impact.

We disagree with SBA that our reliance on *Mid-Tex* is misplaced. In *Mid-Tex,* the court accepted the Commission's conclusion that virtually all of the public utilities that the Commission regulates do not fall within the RFA's meaning of the term ''small entities.'' *Mid-Tex* involved a rule that applies to *all* public utilities. The Open Access Final Rule applies to only those public utilities that own, control or operate interstate transmission facilities, which are a subset of the group of public utilities for which *Mid-Tex* did not require the preparation of a regulatory flexibility analysis.[890]

SBA attempts to distinguish *Mid-Tex* by postulating that the Commission should have attempted to predict how many new entrants into a deregulated market would be small electric utilities, within the SBA's meaning of that term. *Mid-Tex* held just the opposite, deciding squarely that an agency need only consider the businesses that a regulation directly affects.[891] There is no precedent for SBA's suggestion that the Commission must engage in a hypothetical projection of how many entrants likely to enter a deregulated market may be small electric utilities, and we know of no satisfactory way of making such a projection. Entry into the telecommunications industry, which the SBA offers as a model, involves very different costs, distribution and marketing patterns and entirely different technology. There is no way, from looking at what has happened in the telecommunications industry, that the Commission could project, with any degree of accuracy, how many small electric utilities, if any, will enter the market following the effective date of the Final Open Access Rule.

Finally, SBA overlooks, and NRECA unreasonably discounts, the effect that the Commission's waiver rules have on relieving the burden of the Open Access Final Rule on small entities.[892] The Commission has recently issued a number of orders waiving the requirements of the Open Access Final Rule for a number of small electric utilities.[893] As these cases show, the Commission is carefully evaluating the effect of the Open Access Final Rule on small electric utilities and is granting waivers where appropriate, thus mitigating the economic effect of that rule on small entities. Indeed, as we noted in Order No. 888, 5 small public utilities previously had filed open access tariffs, and we have since, in the cases cited above, granted waivers to approximately 17 small public utilities.[894]

2. Non-Public Utilities

We disagree with NRECA's argument that Order No. 888 imposes burdens upon non-public utilities. As we noted in the Final Rule, we do not have jurisdiction to regulate non-public utilities' rates, terms and conditions of transmission service under sections 205 and 206 of the FPA, and there is no requirement in Order No. 888 that non-public utilities file open access tariffs.[895]

In addition, under the waiver provisions of the Open Access Final Rule, small non-public utilities may seek waiver from the reciprocity provision. As reflected in the cases cited above, the Commission has granted waivers of the reciprocity provision to 10 small non-public electric utilities and issued disclaimers of jurisdiction with respect to 19 small electric utilities, thus mitigating the effect of the Open Access Final Rule on small non-public electric utilities.

B. Docket No. RM94–7–000 (Stranded Cost Final Rule)

1. Public Utilities

No rehearing requests addressed this matter.

2. Non-Public Utilities

In Order No. 888, the Commission indicated that the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities because the stranded cost issue would only arise in a proceeding under sections 211 and 212 of the FPA when, in directing transmission, the Commission addresses the stranded cost issue in determining a just and reasonable rate. NRECA counters that the stranded cost issue will ''arise: any time a non-public utility is required to

[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).

[893] 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.

[894] 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.'').

render reciprocal transmission service, and loses a customer as a result of rendering that service, or a TDU loses a customer to an open access public utility transmission provider.'' [896] NRECA submits that the adverse economic impact on small non-public utilities will ''arise'' from the stranding of costs, not from the utilities' participation in proceedings at the Commission, and that the Commission ''cannot in good conscience fail at least to probe the potential adverse economic impact on small non-public utilities of the stranded costs they incur as a direct result of Order No. 888.''

Notwithstanding NRECA's argument that small non-public utilities may experience stranded costs outside of a section 211/212 proceeding, as we explain in Section IV.J.1, *supra,* our jurisdiction over the recovery of stranded costs by non-public utilities, and thus our ability to permit an opportunity for recovery of such costs, is limited by statute. With the exception of our section 210 interconnection and sections 211–212 transmission rate jurisdiction, we do not have jurisdiction over the rates of non-public utilities. Because the stranded cost issue would primarily arise as to non-public utilities over which the Commission has jurisdiction in a proceeding under sections 211 and 212 of the FPA when, in directing transmission, the Commission addresses the stranded cost issue in determining a just and reasonable rate,[897] we concluded that the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities.

Because the Commission does not have rate jurisdiction over non-public utilities other than through sections 210, 211 and 212, the Commission does not have the authority to allow them to recover stranded costs other than through rates set under section 212. However, we clarify that nothing in the Final Rule was intended to preclude non-public utilities from including stranded cost provisions in voluntary reciprocity tariffs or from otherwise recovering stranded costs under applicable law. Thus, a non-public utility that chooses voluntarily to offer an open access tariff for purposes of demonstrating that it meets the reciprocity provision can include a stranded cost provision in its tariff. However, adjudication of any stranded cost claims under that tariff is not subject to the Commission's jurisdiction.[898] If a non-public utility wishes to recover stranded costs pursuant to a tariff or otherwise, it can seek to do so subject to the review of the appropriate regulatory or judicial authority.

[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.

VII. Information Collection Statement

Order No. 888 contained an information collection statement for which the Commission obtained approval from the Office of Management and Budget (OMB).[899] Given that this order on rehearing makes only minor revisions to Order No. 888, none of which is substantive, OMB approval for this order will not be necessary. However, the Commission will send a copy of this order to OMB, for informational purposes only.

The information reporting requirements under this order are virtually unchanged from those contained in Order No. 888. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention Michael Miller, Information Services Division, (202) 208–1415], and the Office of Management and Budget [Attention: Desk Officer for the Federal Energy Regulatory Commission (202) 395–3087].

VIII. Effective Date

Changes to Order No. 888 made in this order on rehearing will become effective on May 13, 1997.

List of Subjects 18 CFR Part 35

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

By the Commission. Commissioners Hoecker and Massey dissented in part with separate statements attached.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends part 35, chapter I, title 18 of the *Code of Federal Regulations,* as set forth below.

[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.

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Part 35 is amended by revising § 35.26 to read as follows:

§ 35.26 Recovery of stranded costs by public utilities and transmitting utilities.

(a) *Purpose.* This section establishes the standards that a public utility or transmitting utility must satisfy in order to recover stranded costs.

(b) *Definitions.*—(1) *Wholesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) 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 that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

(2) *Wholesale requirements customer* means a customer for whom a public utility or transmitting utility provides by contract any portion of its bundled wholesale power requirements.

(3) *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).

(4) *Wholesale requirements contract* means a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements.

(5) *Retail stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility to provide service to a retail customer that subsequently becomes, in whole or in part, an unbundled retail transmission services customer of that public utility.

(6) *Retail transmission services* means the transmission of electric energy sold, or to be sold, in interstate commerce directly to a retail customer.

(7) *New wholesale requirements contract* means any *wholesale requirements* contract executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994.

(8) *Existing wholesale requirements* contract means any *wholesale*

requirements contract executed on or before July 11, 1994.

(c) *Recovery of wholesale stranded costs.*—(1) *General requirement.* A public utility or transmitting utility will be allowed to seek recovery of wholesale stranded costs only as follows:

(i) No public utility or transmitting utility may seek recovery of wholesale stranded costs if such recovery is explicitly prohibited by a contract or settlement agreement, or by any power sales or transmission rate schedule or tariff.

(ii) No public utility or transmitting utility may seek recovery of stranded costs associated with a new wholesale requirements contract if such contract does not contain an exit fee or other explicit stranded cost provision.

(iii) If wholesale stranded costs are associated with a new wholesale requirements contract containing an exit fee or other explicit stranded cost provision, and the seller under the contract is a public utility, the public utility may seek recovery of such costs, in accordance with the contract, through rates for electric energy under sections 205–206 of the FPA. The public utility may not seek recovery of such costs through any transmission rate for FPA section 205 or 211 transmission services.

(iv) If wholesale stranded costs are associated with a new wholesale requirements contract, and the seller under the contract is a transmitting utility but not also a public utility, the transmitting utility may not seek an order from the Commission allowing recovery of such costs.

(v) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the public utility may seek recovery of stranded costs only as follows:

(A) If either party to the contract seeks a stranded cost amendment pursuant to a section 205 or section 206 filing under the FPA made prior to the expiration of the contract, and the Commission accepts or approves an amendment permitting recovery of stranded costs, the public utility may seek recovery of such costs through FPA section 205–206 rates for electric energy.

(B) If the contract is not amended to permit recovery of stranded costs as described in paragraph (c)(1)(v)(A) of this section, the public utility may file a proposal, prior to the expiration of the contract, to recover stranded costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to the customer.

(vi) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a transmitting utility but not also a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the transmitting utility may seek recovery of stranded costs through FPA section 211–212 transmission rates.

(vii) If a retail customer becomes a legitimate wholesale transmission customer of a public utility or transmitting utility, *e.g.,* through municipalization, and costs are stranded as a result of the retail-turned-wholesale customer's access to wholesale transmission, the utility may seek recovery of such costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to that customer.

(2) *Evidentiary demonstration for wholesale stranded cost recovery.* A public utility or transmitting utility seeking to recover wholesale stranded costs in accordance with paragraphs (c)(1) (v) through (vii) of this section must demonstrate that:

(i) It incurred costs to provide service to a wholesale requirements customer or retail customer based on a reasonable expectation that the utility would continue to serve the customer;

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a wholesale requirements customer of the utility, or, in the case of a retail-turned-wholesale customer, had the customer remained a retail customer of the utility; and

(iii) The stranded costs are derived using the following formula: Stranded Cost Obligation = (Revenue Stream Estimate—Competitive Market Value Estimate) × Length of Obligation (reasonable expectation period).

(3) *Rebuttable presumption.* If a public utility or transmitting utility seeks recovery of wholesale stranded costs associated with an existing wholesale requirements contract, as permitted in paragraph (c)(1) of this section, and the existing wholesale requirements contract contains a notice provision, there will be a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision.

(4) *Procedure for customer to obtain stranded cost estimate.* A customer under an existing wholesale requirements contract with a public utility seller may obtain from the seller an estimate of the customer's stranded cost obligation if it were to leave the public utility's generation supply system by filing with the public utility a request for an estimate at any time prior to the termination date specified in its contract.

(i) The public utility must provide a response within 30 days of receiving the request. The response must include:

(A) An estimate of the customer's stranded cost obligation based on the formula in paragraph (c)(2)(iii) of this section;

(B) Supporting detail indicating how each element in the formula was derived;

(C) A detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract;

(D) An estimate of the amount of released capacity and associated energy that would result from the customer's departure; and

(E) The utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs.

(ii) If the customer disagrees with the utility's response, it must respond to the utility within 30 days explaining why it disagrees. If the parties cannot work out a mutually agreeable resolution, they may exercise their rights to Commission resolution under the FPA.

(5) A customer must be given the option to market or broker a portion or all of the capacity and energy associated with any stranded costs claimed by the public utility.

(i) To exercise the option, the customer must so notify the utility in writing no later than 30 days after the public utility files its estimate of stranded costs for the customer with the Commission.

(A) Before marketing or brokering can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount and the price of capacity and associated energy the customer is entitled to schedule, and the duration of the customer's marketing or brokering of such capacity and energy.

(ii) If agreement over marketing or brokering cannot be reached, and the parties seek Commission resolution of disputed issues, upon issuance of a Commission order resolving the disputed issues, the customer may reevaluate its decision in paragraph (c)(5)(i) of this section to exercise the marketing or brokering option. The customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

(iii) If a customer undertakes the brokering option, and the customer's brokering efforts fail to produce a buyer within 60 days of the date of the brokering agreement entered into between the customer and the utility, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula in paragraph (c)(2)(iii) of this section.

(d) *Recovery of retail stranded costs*—(1) *General requirement.* A public utility may seek to recover retail stranded costs through rates for retail transmission services only if the state regulatory authority does not have authority under state law to address stranded costs at the time the retail wheeling is required.

(2) *Evidentiary demonstration necessary for retail stranded cost recovery.* A public utility seeking to recover retail stranded costs in accordance with paragraph (d)(1) of this section must demonstrate that:

(i) It incurred costs to provide service to a retail customer that obtains retail wheeling based on a reasonable expectation that the utility would continue to serve the customer; and

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a retail customer of the utility.

Note: Appendices A and B and statements of Commissioners Hoecker and Massey will not be published in the Code of Federal Regulations.

Appendix A—List of Petitioners

Docket Nos. RM95–8–001 and RM94–7–002

Abbreviation	Petitioner
1. AEC & SMEPA	Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association.
2. AEP	Operating Companies of the American Electric Power System.
3. AL Com	Alabama Public Service Commission.
4. Allegheny	Allegheny Power Service Corporation.
5. AL Municipal	Alabama Municipal Electric Authority.
6. American Forest & Paper	American Forest & Paper Association.
7. AMP-Ohio	American Municipal Power-Ohio, Inc. and Indiana Municipal Power Agency.
8. Anaheim	Cities of Anaheim, Azusa, Banning, Colton and Riverside, California.
9. APPA	American Public Power Association.
10. AR Com	Arkansas Public Service Commission.
11. Arkansas Cities	Arkansas Cities and Farmers Electric Cooperative.
12. Associated EC	Associated Electric Cooperative, Inc.
13. Atlantic City	Atlantic City Electric Company.
14. Basin EC	Basin Electric Power Cooperative.
15. Blue Ridge	Blue Ridge Power Agency, Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc.
16. BPA	Bonneville Power Administration.
17. Cajun	Ralph R. Mabey, Chapter II Trustee for Cajun Electric Power Cooperative, Inc.
18. California DWR	California Department of Water Resources.
19. Carolina P&L	Carolina Power & Light Company.
20. CCEM	Coalition for a Competitive Electric Market (consisting of Coastal Electric Services Company, Destec Power Services, Inc., Electric Clearinghouse, Inc., Enron Power Marketing, Inc., Equitable Power Services Company, KCS Power Marketing, Inc., MidCon Power Services Corp. and Vitol Gas & Electric Services, Inc).
21. Centerior	Centerior Energy Corporation.
22. Central Illinois Light	Central Illinois Light Company.
23. Central Minnesota Municipal	Central Minnesota Municipal Power Agency.
24. Central Montana EC	Central Montana Electric Power Cooperative, Inc.
25. Cleveland	Cleveland Public Power.
26. CO Consumers Counsel	Colorado Office of Consumer Counsel.
27. Coalition for Economic Competition.	Coalition for Economic Competition Consisting of Consolidated Edison Company of New York, Inc., General Public Utilities Corporation, Illinois Power Company, Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Northeast Utilities, and Rochester Gas and Electric Corporation.
28. ConEd	Consolidated Edison Company of New York, Inc.
29. Connecticut DEP	State of Connecticut Department of Environmental Protection.
30. Consumers Power	Consumers Power Company.
31. Cooperative Power	Cooperative Power.
32. CSW Operating Companies	Central Power and Light, West Texas Utilities Company, Public Service Company of Oklahoma and Southwestern Electric Power Company.
33. CVPSC	Central Vermont Public Service Corporation.
34. Dairyland	Dairyland Power Cooperative.
35. Dalton	City of Dalton, Georgia.
36. Detroit Edison	Detroit Edison Company.
37. Dispute Resolution	Communications and Energy Dispute Resolution Associates.
38. Duquesne	Duquesne Light Company.
39. EEI	Edison Electric Institute.
40. EGA	Electric Generation Association.
41. El Paso	El Paso Electric Company.
42. ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute, Chemical Manufacturers Association and Council of Industrial Boiler Owners.
43. Entergy	Entergy Services, Inc.
44. EPRI	Electric Power Research Institute.
45. FL Com	Florida Public Service Commission.
46. Florida Power Corp	Florida Power Corporation.
47. FMPA	Florida Municipal Power Agency.

Abbreviation	Petitioner
48. FPL	Florida Power & Light Company.
49. Freedom Energy Co	Freedom Energy Corporation, LLC.
50. Hoosier EC	Hoosier Energy Rural Electric Cooperative.
51. IA Com	Iowa Utilities Board.
52. IL Com	Illinois Commerce Commission.
53. IL Industrials	Illinois Industrial Energy Consumers.
54. Illinois Power	Illinois Power Company.
55. IMPA	Indiana Municipal Power Agency.
56. IN Com	Indiana Utility Regulatory Commission.
57. IN Consumer	Indiana Office of Utility Consumer Counselor.
58. Indianapolis POL	Indianapolis Power & Light Company.
59. IN Industrials	Citizens Action Coalition of Indiana, Inc., Indiana Industrial Energy Consumers, Inc. and Indianapolis Power & Light Company.
60. Joint Commenters	Joint Commenters Supporting Clear Air and Fair Corporation.
61. KCPL	Kansas City Power & Light Company.
62. LEPA	Louisiana Energy and Power Authority.
63. Local Furnishing Utilities	Local Furnishing Utilities (Long Island Lighting Company, Nevada Power Company, San Diego Gas & Electric Company and Tuscon Electric Power Company).
64. MA Municipals	Twenty Four Massachusetts Municipals.
65. Maine Public Service	Maine Public Service Company.
66. MI Com	Michigan Public Service Commission and New Hampshire Public Utilities Commission.
67. Michigan Systems	Michigan Public Power Agency, Michigan South Central Power Agency, and Wolverine Power Supply Co-operative, Inc.
68. Minnesota P&L	Minnesota Power & Light Company.
69. MN DPS	Minnesota Department of Public Service and Minnesota Public Utilities Commission.
70. MO/KS Coms	Missouri Public Service Commission and Kansas Corporation Commission.
71. Montana Power	Montana Power Company.
72. Montana-Dakota Utilities	Montana-Dakota Utilities Company.
73. Multiple Intervenors	Multiple Intervenors.
74. NARUC	National Association of Regulatory Utility Commissioners.
75. NASUCA	National Association of State Utility Consumer Advocates.
76. NCMPA	North Carolina Municipal Power Agency Number 1.
77. NE Public Power District	Nebraska Public Power District.
78. NIMO	Niagara Mohawk Power Corporation.
79. NJ BPU	New Jersey Board of Public Utilities.
80. North Jersey	North Jersey Energy Associates.
81. NRECA	National Rural Electric Cooperative Association.
82. NU	Northeast Utilities Service Company.
83. Nuclear Energy Institute	Nuclear Energy Institute.
84. Nucor	Nucor Corporation.
85. NWRTA	Northwest Regional Transmission Association.
86. NY AG	New York State Attorney General.
87. NY Com	Public Service Commission of the State of New York.
88. NY Municipals	Municipal Electric Utilities Association of New York States.
89. NY Utilities	Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation.
90. NYPP	New York Power Pool.
91. NYSEG	New York State Electric & Gas Corporation.
92. Occidental Chemical	Occidental Chemical Corporation.
93. Oglethorpe	Oglethorpe Power Corporation.
94. OH Com	Public Utilities Commission of Ohio.
95. OH Consumers' Counsel	Ohio Office of Consumers' Counsel.
96. Ohio Valley	Ohio Valley Electric Corporation and Indiana-Kentucky Electric Corporation.
97. Oklahoma G&E	Oklahoma Gas and Electric Company Inc.
98. Ontario Hydro	Ontario Hydro.
99. PA Com	Pennsylvania Public Utility Commission.
100. PA Coops	Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc.
101. PA Munis	Pennsylvania Municipal Electric Association.
102. PacifiCorp	PacifiCorp.
103. PSE&G	Public Service Electric and Gas Company.
104. PSNM	Public Service Company of New Mexico.
105. Public Service Co of CO	Public Service Company of Colorado.
106. Puget	Puget Sound Power & Light Company.
107. Redding	City of Redding, California.
108. San Francisco	City and County of San Francisco.
109. Santa Clara	City of Santa Clara, California.
110. SBA	United States Small Business Administration, Office of Advocacy.
111. SC Public Service Authority	South Carolina Public Service Authority.
112. SoCal Edison	Southern California Edison Company.
113. Southern	Southern Company Services, Inc.
114. Southwestern	Southwestern Public Service Company.
115. Speciality Steel	Speciality Steel Industry of North America.
116. Suffolk County	Suffolk County (New York) Electric Agency.
117. SWRTA	Southwest Regional Transmission Association.

Abbreviation	Petitioner
118. Tallahassee	City of Tallahassee, Florida.
119. TANC	Transmission Agency of Northern California.
120. TAPS	Transmission Access Policy Study Group.
121. TDU Systems	Transmission Dependent Utility Systems.
122. Texaco	Texaco Inc.
123. Tucson Power	Tucson Electric Power Company.
124. Turlock	Turlock Irrigation District.
125. TX Com	Public Utility Commission of Texas.
126. Umatilla EC	Umatilla Electric Cooperative.
127. Union Electric	Union Electric Company.
128. Utilities For Improved transition.	Utilities For an Improved Transition (consisting of Associated Electric Cooperative, Inc., Boston Edison Company, Central Vermont Public Service Corporation, Montaup Electric Company, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation).
129. VA Com	Staff of the Virginia State Corporation Commission.
130. Valero	Valero Power Services Company.
131. VEPCO	Virginia Electric and Power Company.
132. VT DPS	Vermont Department of Public Service.
133. Wabash	Wabash Valley Power Association, Inc.
134. Washington Water Power	Washington Water Power Company.
135. WI Com	Public Service Commission of Wisconsin.
136. Wisconsin Municipals	Municipal Electric Utilities of Wisconsin.
137. WY Com	Public Service Commission of Wyoming.

Appendix B—Pro Forma Open Access Transmission Tariff

Table of Contents

I. Common Service Provisions

1 Definitions

1.1 Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment until amended by the Transmission Provider or modified by the Commission.

1.3 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4 Commission: The Federal Energy Regulatory Commission.

1.5 Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.6 Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) Provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.8 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.10 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.11 Eligible Customer: (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider. (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.12 Facilities Study: An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.13 Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.14 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.15 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.16 Load Ratio Share: Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III the Tariff and calculated on a rolling twelve month basis.

1.17 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.18 Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.19 Native Load Customers: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.20 Network Customer: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.21 Network Integration Transmission Service: The transmission service provided under Part III of the Tariff.

1.22 Network Load: The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.23 Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.24 Network Operating Committee: A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.25 Network Resource: Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.26 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.27 Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.28 Open Access Same-Time Information System (OASIS): The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.29 Part I: Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II: Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III: Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.33 Point(s) of Delivery: Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.34 Point(s) of Receipt: Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.35 Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.37 Receiving Party: The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.38 Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.39 Reserved Capacity: The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.40 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.41 Service Commencement Date: The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.42 Short-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.43 System Impact Study: An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.44 Third-Party Sale: Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.45 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.46 Transmission Provider: The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.47 Transmission Provider's Monthly Transmission System Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.48 Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.49 Transmission System: The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2. Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transmission Capability: For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

3. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation Sources Service: The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities). In the event available transmission capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds: This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates.

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

7 Billing and Payment

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

7.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty

(60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues: Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-to-Point Transmission Service

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term: The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority: Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis *i.e.*, in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in Federal Register] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8 , for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements: The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 . Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than *10:00 a.m.* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to *twenty (20) minutes* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term: Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in Federal Register] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8 , for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements: The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than *2:00 p.m.* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to *twenty (20) minutes* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service: The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm

Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions: The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transmission Capability: A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the Transmission Provider's OASIS (Section) is contained in Attachment of the Tariff. In the event sufficient transmission capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement: If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System: If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

15.5 Deferral of Service: The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

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

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers: Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

d. The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

e. The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

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

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

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

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

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

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

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

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

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

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

17.3 Deposit: A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

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

17.5 Response to a Completed Application: Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available 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

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 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 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

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 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 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

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 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 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.

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.''

Deference in this context is a slippery proposition for other reasons, too. Naturally, states may perceive equity considerations, cost causation principles, [1] and market risk factors[2] 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

[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).

[2] Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, Order No. 528–A, 54 FERC ¶ 61,095 (1991).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 37

[Docket No. RM95–9–001; Order No. 889–A]

Open Access Same-Time Information System and Standards of Conduct

Issued March 4, 1997.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule; order on rehearing.

SUMMARY: The Federal Energy Regulatory Commission is revising its policy on posting discounts to be consistent with changes in the discount policy that we simultaneously are implementing in Order No. 888–A. Additionally, we are making other minor revisions to 18 CFR Part 37—which contains rules establishing and governing transmission information networks and standards of conduct—to be responsive to arguments made on rehearing and to make the regulations operate more smoothly.

In addition, the Commission requests that the How Working Group propose the necessary changes in the Standards and Protocols document and the Data Dictionary by June 2, 1997 to address four issues.

EFFECTIVE DATE: This rule is effective on May 13, 1997.

FOR FURTHER INFORMATION CONTACT:

Marvin Rosenberg (Technical Information), Office of Economic Policy, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426, (202) 208–1283.

William C. Booth (Technical Information), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426, (202) 208–0849.

Gary D. Cohen (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426, (202) 208–0321.

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, N.E., Washington, D.C. 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. 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 available on CIPS in ASCII and Wordperfect 5.1 format. CIPS user assistance is available at 202–208–2474.

CIPS is also available through the Fed World system. Telnet software is required. To access CIPS via the Internet, point your browser to the URL address: http://www.fedworld.gov and select the ''Go to the FedWorld Telnet Site'' button. When your Telnet software connects you, log onto the FedWorld system, scroll down and select FedWorld by typing: 1 and at the command line then typing: /go FERC. FedWorld may also be accessed by Telnet at the address fedworld.gov.

Finally, the complete text on diskette in WordPerfect format may be purchased from the Commission's copy contractor, La Dorn Systems Corporation. La Dorn Systems Corporation is also located in the Public Reference Room at 888 First Street, N.E., Washington, D.C. 20426.

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