Investment Company Act [15 U.S.C. 80a–24, –37(a)].

Text of Form Amendments

For the reasons set out in the preamble, Form 24F–2, referenced in § 274.24, Title 17, Chapter II of the Code of Federal Regulations, is amended as follows:

PART 274—FORMS PRESCRIBED UNDER THE INVESTMENT COMPANY ACT OF 1940

1. The authority citation for Part 274 continues to read as follows:

Authority: 15 U.S.C. 77f, 77g, 77h, 77j, 77s, 78c(b), 78*l*, 78m, 78n, 78o(d), 80a–8, 80a–24, and 80a–29, unless otherwise noted.

2. Form 24F–2 (referenced in § 274.24) is amended by revising the second and third sentences of Instruction C.9 to Item 5(vii) to read as follows:

Note: Form 24F–2 does not, and the amendments will not, appear in the *Code of Federal Regulations.*

Form 24F–2

Annual Notice of Securities Sold Pursuant to Rule 24f–2

* * * * *

Instructions

* * * * *

C. Computation of Registration Fee

* * * * *

9. Item 5(vii)—* * * As of November 28, 1997, the fee rate was $295 per $1,000,000 offered or sold (prorated for amounts less than $1,000,000). The registration fee is calculated by multiplying the aggregate offering or sales amount by .000295. * * *

* * * * *

For the Commission, by the Office of the Secretary, pursuant to delegated authority.

Dated: December 2, 1997.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 97–31961 Filed 12–8–97; 8:45 am]

BILLING CODE 8010–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket Nos. RM95–8–003 and RM94–7–004; Order No. 888–B]

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

Issued November 25, 1997.

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Final rule; order on rehearing.

SUMMARY: The Federal Energy Regulatory Commission affirms, with certain clarifications, the fundamental calls made in its order on rehearing of the final rule in this proceeding. The final rule directed public utilities to open their transmission lines to competitors and to offer them the same charges and conditions they apply to themselves. The rule also gave utilities an opportunity to seek recovery of certain stranded costs, i.e., costs that were prudently incurred to serve customers that use open access transmission under the final rule to shift to another power supplier. The Commission in this order clarifies its position on recovery of stranded costs in the case of municipalizations and municipal annexations, where customers previously served by a public utility become customers of a municipal utility instead.

EFFECTIVE DATE: February 9, 1998.

FOR FURTHER INFORMATION CONTACT:

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Deborah B. Leahy (Legal Information—Docket No. RM94–7–004), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 208–2039.

Daniel T. Hedberg (Technical Information—Docket No. RM95–8–003), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 208–0243.

Joseph M. Power (Technical Information—Docket No. RM94–7–004), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 208–0243.

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 Room 2A, 888 First Street, N.E., Washington, D.C. 20426. 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 located 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, also provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user. CIPS can be accessed over the Internet by pointing your browser to the URL address: http://www.ferc.fed.us. Select the link to CIPS. The full text of this document can be viewed, and saved, in ASCII format and an entire day's documents can be downloaded in WordPerfect 6.1 format by searching the miscellaneous file for the last seven days. CIPS also 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 6.1 format. CIPS user assistance is available at 202–208–2474.

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Before Commissioners: James J. Hoecker, Chairman; Vicky A. Bailey, and William L. Massey.

I. Introduction

In this order, the Commission affirms, with certain clarifications, the fundamental calls made in Order No. 888–A. [1]

II. Public Reporting Burden

This order on rehearing issues a minor revision to Order Nos. 888 and 888–A.[2] We find, after reviewing this revision, that it does not increase or decrease the public reporting burden.

Order No. 888 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 burden estimate contained in Order No. 888 as a starting point, we evaluated the public burden estimate in light of the revision contained in this order and assessed whether the estimate needed revision. We have concluded, given the minor nature of the revision, 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 Order Nos. 888 and 888–A. 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 Order Nos. 888 and 888–A, as revised and clarified 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 Order Nos. 888 and 888–A, for the collection, efficient management, and use of the required information.

Persons wishing to comment on the collections of information required by Order Nos. 888 and 888–A, 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. 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 Order No. 888, the Commission required 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. Order No. 888 required 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. To implement the requirements of comparable open access transmission, the Commission required all public utilities that own, operate or control interstate transmission facilities to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory transmission service. In Order No. 888, the Commission established rules for discounting practices, provisions governing priority of service and curtailment, and a right of first refusal for all firm transmission customers. In addition, Order No. 888 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.

With regard to stranded costs, Order No. 888 gives utilities the opportunity to seek to recover legitimate, prudent, and verifiable wholesale stranded 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. 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 Commission adopted a revenues lost approach for calculating a utility's stranded costs, and determined that stranded costs should be recovered from the customer that caused the costs to be incurred. The Commission decided in Order No. 888 to be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers, but not to be the primary forum in cases involving existing municipal utilities that annex retail customer service territories. Order No. 888 also clarified whether and when the

[1] As described further below, the Commission is making one revision to the pro forma open access transmission tariff. *See infra* Section IV.A.10.f and Appendix B. Because of this single revision and its minor nature, the Commission concludes that it would be administratively burdensome to require all public utilities with pro forma open access transmission tariffs on file with the Commission to submit compliance tariffs to reflect the revision. Accordingly, the Commission will amend all pro forma open access transmission tariffs currently on file with the Commission to incorporate the tariff revision and no tariff compliance filings will be necessary.

[2] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997).

[3] 61 FR 21540, 21543; FERC Stats. & Regs. ¶ 31,036 at 31,638 (1996). In Order No. 888-A, the Commission concluded that its estimate of the public reporting burden in that order on rehearing remained unchanged from its estimate in Order No. 888. 62 FR 12274, 12280; FERC Stats. & Regs. ¶ 31,048 at 30,183 (1997).

Commission may address stranded costs caused by retail wheeling and the extent of the Commission's jurisdiction over unbundled retail transmission. The Commission determined that the only circumstance in which it will entertain requests for the recovery of stranded costs caused by unbundled 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.

Order No. 888 further addressed 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. The Commission determined that pre-existing contracts would continue to be honored until such time as they were revised or terminated. The Commission 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, and that public utilities would 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.

In Order No. 888–A, the Commission reaffirmed its basic determinations in Order No. 888, with certain clarifications. For example, it revised the discounting requirements to better permit the ready identification of discriminatory discounting practices while also providing greater discount flexibility, and it clarified several aspects of the reciprocity condition. It also clarified that if utilities under *Mobile-Sierra* 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. In addition, the Commission reconsidered its decision in Order No. 888 not to be the primary forum for determining stranded cost recovery in cases involving municipal annexation and concluded that such cases should fall within the Commission's province.

In this order, the Commission affirms, with certain clarifications, the fundamental calls made in Order No. 888–A.

IV. Discussion

A. Open Access Issues

1. Discounting

A number of entities seek rehearing and/or clarification of the Commission's modified discounting policy that requires transmission providers to offer the same discount over all unconstrained paths to the same point of delivery.[4] Several of these entities assert that the Commission's modified policy encourages discriminatory behavior.[5] NRECA and TDU Systems argue that the Commission's policy opens the door to customer-by-customer discrimination (including discrimination by the transmission provider in favor of its native load customers) because it is likely that only one or a few customers would want transmission service to a particular delivery point. They also assert that the transmission provider unreasonably could discount service on a path where it has load, but decline discounts to another delivery point halfway along the same path.[6] They further contend that the Commission's new policy ''swings the pendulum too far in the direction of allowing price discrimination'' by the transmission monopolist. According to TDU Systems, the Commission's policy ''does not confine the transmission provider's incentive to give discounts for its own transmission uses to those instances, and only those instances, in which such discounts are economically justified.'' TDU Systems adds that ''the OASIS reporting will be inadequate to remedy discrimination in discounting short-term non-firm transmission, since the transactions will be over before complaints can even be filed.'' [7]

TAPS likewise asserts that ''[b]y allowing transmission providers to select the delivery points meriting a discount, the Commission is encouraging discriminatory behavior that it will be unable to remedy'' through an after-the-fact complaint proceeding.[8] It maintains that the Commission's approach ''makes it less likely that transmission providers will provide competitors non-firm transmission service at rates reflecting the lower quality of the service (if the Commission permits non-firm transmission rates to be capped at the firm rate).'' [9] It notes that TAPS members—

> have experienced withdrawal of discounts they have enjoyed under the Order No. 888 discounting policy and have seen evidence that the revised policy will be applied by transmission providers to offer discounts to each other, in the hope, expectation, or tacit agreement that they will be offered reciprocal discounts on the other transmission provider's system when requested, while a transmission dependent utility must always pay full freight. [10]

APPA asserts that the Commission properly required all discount negotiations to occur on the OASIS, but erroneously removed the requirement that affiliate discounts be offered for all service on unconstrained paths. It argues that the Commission ''has failed to balance its policy of ending discrimination in wholesale transmission services with the objective to send proper price signals to transmission providers and customers.'' [11] Under the Commission's modified approach, APPA believes that transmission providers can offer discounts on a very selective basis—''public utility transmission providers will have the ability to provide discounts to affiliates in ways that exclude smaller utilities, including municipal utilities, from receiving those same discounts.'' [12]

These entities propose several approaches to resolve the competitive problems they believe are associated with the Commission's modified approach to discounting. NRECA states that the Commission should revert to its Order No. 888 policy or require that discounts be offered on all unconstrained paths serving all similarly situated customers. NRECA and TDU Systems (which supports the second alternative) state that the alternative approach could be accomplished by requiring discounts on all unconstrained ''posted paths,'' or, if a discount is provided within a particular unconstrained area, the transmission provider should be required to offer the same discount on all unconstrained paths within the same area. Similarly, TAPS states that the Commission should revert to its Order No. 888 policy or, at a minimum, ''the discounts should be extended to all delivery points in the same unconstrained portion of the transmission provider's transmission

[4] Arizona, NRECA, TAPS, and TDU Systems. APPA also raises this issue, but APPA filed its request for rehearing out-of-time on April 4, 1997. APPA failed to file its rehearing request within the 30 day period required by the Federal Power Act. *See* 16 U.S.C. 825l(a). Accordingly, we will not accept the rehearing request for filing, but will accept the pleading as a motion for reconsideration.

[5] NRECA, TDU Systems, TAPS and APPA.

[6] *See also* TAPS.

[7] TDU Systems at 8–10.

[8] TAPS at 17.

[9] *Id*. at 18 (footnote omitted).

[10] *Id*.

[11] APPA at 17.

[12] *Id*. at 19.

system plus other similarly situated customers (from an operational/cost, rather than competitive, viewpoint).'' [13] Moreover, APPA states that the Commission should revert to Order No. 888 or, in the alternative, ''should require uniform discounts across interfaces and within control areas, or, at a minimum, within unconstrained zones.'' [14]

TAPS adds that the best way to promote efficient transmission usage and competitive bulk power markets is ''to set non-firm rates at the lowest reasonable rate, in accordance with the Commission's statutory mandate * * *. It is unreasonable to rely on discounting, especially delivery point-specific discounts, to ensure that customers are not charged firm rates for interruptible, low priority, non-firm service.'' [15] It requests that the Commission clarify that it will actively exercise its responsibility to ensure that customers are not overcharged for non-firm service.

Arizona, on the other hand, seeks to narrow the Commission's revised discounting policy. It requests that the Commission allow a transmission provider to offer varying degrees of discount depending upon whether—

> (1) transactions over a particular path alleviate constraints on another transmission path, (2) certain transmission paths are loaded to a different degree than other paths, and (3) initial discounts encourage a sufficient number of transactions. [[16]]

For example, it asserts that ''there could be multiple paths to the same delivery point, with each path potentially warranting different discounting treatment. A steep discount may be appropriate on one unutilized transmission path to encourage counter-wheeling transactions that will alleviate constraints on another path into the delivery point, whereas a smaller discount (or no discount at all) may be appropriate on another unconstrained, but highly valued, path into the delivery point.'' [17]

With respect to its second point, Arizona asserts that a transmission path with relatively little available transmission capability (ATC) deserves a lower discount than a transmission path with relatively high ATC. It urges the Commission to clarify ''whether a transmission path that has an ATC equal to 80% of [total transmission capability (TTC)] should be discounted to the same degree as a transmission path that has an ATC equal to only 30% of TTC.'' [18] As to its third point, it seeks clarification that it ''may initially offer a steep discount on a transmission path into a particular delivery point to encourage transactions, but reduce the discount as more and more transactions take place over that path.'' [19]

American Electric Power System (AEP) responds to TAPS' assertion that transmission providers will only offer discounts to each other as evidenced by a printout from AEP's OASIS under which TAPS contends ''discounts are now available only to delivery points of other transmission providers, not those of TDUs.'' [20] AEP indicates that, contrary to TAPS' assertion, it offers discounts to any transmission customer that has alternatives to using AEP's transmission system. It notes that this is consistent with the Order No. 888–A statement that a transmission provider should discount only if necessary to increase throughput on its system. It also adds that no customer is being charged rates that exceed a just and reasonable, cost-based rate. According to AEP, ''[t]o charge customers without alternatives less than the cost-based rate would be unduly discriminatory to AEP's native load customers who would otherwise have to make up the revenues not recovered from such customers.'' [21] Moreover, because discounting must be conducted through the OASIS, AEP declares that there is no chance that a transmission provider will use discounting for any purpose other than to increase throughput. AEP also opposes TAPS' request to establish a price cap for non-firm service below that for firm service. It claims that such a change would allow customers on largely unconstrained transmission systems such as AEP's to game the system by requesting non-firm service priced at a low level with the knowledge that the service is essentially the equivalent of firm service.

Commission Conclusion. We deny the requests for rehearing of our discounting policy. In Order No. 888–A, we addressed certain concerns raised by various parties on rehearing regarding our prior discounting policy and adopted a more balanced approach that would provide incentives to transmission providers to operate the transmission grid efficiently while ensuring that they do so in a not unduly discriminatory manner.[22] Our balanced approach requires that (1) a transmission provider should discount only if necessary to increase throughput on its system, (2) any offer of a discount and the details of any agreed upon discount transaction must be posted on the OASIS (including any negotiation, *i.e.*, any offers and counteroffers, of the discount), and (3) a 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.

We believe that this approach is a reasonable and workable means to permit transmission providers to provide discounts in a not unduly discriminatory manner. Transmission providers will not have unnecessary restrictions on their ability to increase throughput on their transmission systems, which accrues to the benefit of all of their firm customers, while OASIS will allow the Commission and other users of the system to monitor for instances of unduly discriminatory behavior by such transmission providers.[23]

In this regard, we also disagree that posting of discounts on OASIS is inadequate for short-term discounts because the transactions will be over before a complaint could be filed. All complaint proceedings occur after the fact, but we believe that such proceedings nevertheless act as a deterrent to improper behavior. The Commission will not be reluctant to impose appropriate sanctions in instances where transmission providers engage in unduly discriminatory discounting practices. Moreover, any alternative would likely require a preapproval process that could, as parties to this proceeding have argued, shut down a substantial portion of the hourly transactions in short-term markets that depend upon discounted transmission to go forward.

We see no need at this time to adopt a more restrictive discounting policy

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[13] TAPS at 19.

[14] APPA at 20.

[15] TAPS at 20.

[16] Arizona at 4.

[17] *Id*. at 5 (footnote omitted).

[18] *Id*. at 6 n.12.

[19] *Id*. at 6 (footnote omitted).

[20] AEP at 3. On April 17, 1997, AEP filed an answer to the request for clarification and rehearing of TAPS. In the circumstances presented, we will accept the answer notwithstanding our general prohibition on allowing answer notwithstanding our general prohibition on allowing answers to rehearing requests. *See* 18 CFR 385.713(d).

[21] *Id*. at 4 (emphasis in original).

[22] FERC Stats. & Regs. ¶ 31,048 at 30,274–76.

[23] With respect to Arizona's request that a transmission provider be allowed to offer varying degrees of discount depending on the circumstances, we note that this Rule does not reach that level of specificity. A transmission provider is free to implement any discounting proposal which it believes can increase throughput without doing so in an unduly discriminatory manner, provided that the proposal offers the same discount for the same period to all eligible customers on all unconstrained paths that go to the same point(s) of delivery. However, if challenged on complaint, it should be prepared to defend its method. The only alternative is to require no discounting, an approach we reject as contrary to firm customers' interests and efficient grid use.

that could hinder a transmission provider's ability to increase throughput on its system based solely on allegations that the transmission provider may act in an unduly discriminatory manner. The opportunity to monitor the discounting behavior of transmission providers through OASIS will provide data that will allow the Commission to evaluate the adequacy and effectiveness of its discounting policy.[24] Until we see evidence that our discounting policy will not work or see patterns of unduly discriminatory discounting practices, we will continue the Order No. 888–A discounting policy, with the OASIS safeguards in place.

2. Reciprocity

Several entities raise a variety of issues with respect to the Commission's reciprocity condition. NRECA and TDU Systems request clarification that the amendment to section 6 of the pro forma tariff that deleted the words ''in interstate commerce'' was intended to affect only the reciprocity obligation of foreign transmission customers and not the reciprocity obligation of transmission customers located in the United States.[25] They seek clarification that transmission customers within the United States need provide reciprocal service only on facilities used for the transmission of electric energy in interstate commerce and not over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce.

Also with respect to section 6 of the pro forma tariff, NEPOOL takes issue with the additional language that provides that reciprocity applies 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.'' [26] It asserts that the breadth of this language could cause New Brunswick Power Corporation (New Brunswick), a Canadian utility that has engaged in economy and emergency transactions with NEPOOL and made unit sales to New England buyers, to cease or reduce sales in New England. According to NEPOOL, New Brunswick has indicated a concern that it does not have the legal authority to implement a generic open access tariff in New Brunswick. Thus, NEPOOL requests that the Commission provide that where a seller is simply continuing to make sales in the same manner as it did before Order Nos. 888 and 888–A, and is legally unable to provide reciprocity, the reciprocity requirement will not be applicable to it.[27]

TAPS takes issue with the Commission's modified ''safe harbor'' procedure set forth in Order No. 888–A that permits a non-public utility to provide reciprocal service only to the transmission provider from whom it receives open access transmission service. TAPS believes that the Commission's modification is ''an unnecessary step backwards from its expressed aim of remedying past undue discrimination and providing non-discriminatory open access.'' [28] It believes that the transmission provider's access to third party systems will be superior to that of its customers that support the transmission grid. According to TAPS, a customer would be at a disadvantage because it would be forced to resort to a filing under section 211. Thus, it asserts that the safe harbor should be available only to those that offer open access to all eligible wholesale transmission customers. ''At the very least, [it argues,] the special protections offered by the safe harbor should be available only if the non-jurisdictional utility makes its tariff available to the long term customers of the transmission provider.'' [29]

RUS seeks rehearing and/or clarification with respect to a number of reciprocity related issues. RUS first complains that there is confusion regarding the alternatives available to non-public utilities. It asserts that in certain places in Order No. 888–A the Commission indicates that it will no longer allow bilateral agreements (*e.g.*, ''Alternatively, bilateral agreements for transmission service provided by a public utility will not be permitted.''), but that in other places the Commission encourages the use of bilateral agreements (*e.g.*, ''A non-public utility may also satisfy reciprocity through bilateral agreements with a public utility.''). It also notes that Order No. 888–A appears to substitute public utility waivers for the alternative of bilateral agreements. In any event, however, it argues that

> [p]ublic utilities have no incentive to enter into bilateral agreements or to waive the reciprocity requirement for a non-public utility that owns transmission. Indeed, these so-called options effectively invite public utilities to deny access to non-public utilities that have not filed open access tariffs. If a non-public utility cannot qualify for a waiver from the Commission, the public utility can, by denying a waiver or refusing to enter into a bilateral agreement, force the non-public utility to file a reciprocal tariff with the Commission. Moreover, requiring a non-public utility to seek a waiver—whether from the public utility or the Commission—is inconsistent with the Commission's assertions that the provision of open access by non-public utilities is not required, but merely voluntary.[30]

RUS takes issue with the following statement in Order No. 888–A, claiming that it mischaracterizes the RUS program and RUS as anti-competitive:

> 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 argument. Such cooperatives have the option to seek bilateral service agreements. [Order No. 888–A, mimeo at 318].

RUS maintains that it does not place any prohibitions, restrictions, or conditions on financing to electric systems based on rendering reciprocal service. It states that while the Rural Electrification Act places restrictions on RUS financing, it does not prohibit cooperatives from obtaining financing for facilities through non-RUS sources.

RUS seeks clarification that the statement in Order No. 888–A that ''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'' does not mean that if a G&T uses an open access tariff, both the G&T and its distribution system are subject to the reciprocity provision.

RUS also states that although the Commission acknowledges that it lacks jurisdiction to enforce rates charged by non-public utilities in reciprocal open access tariffs and to adjudicate stranded cost claims of non-public utilities, the Commission has indicated that if a non-public utility includes a stranded cost component in a reciprocity tariff, ''the Commission will review that stranded cost provision if a public utility claims that the stranded cost component, as applied, violates the principle of comparability.'' [31] According to RUS, ''any comparability determination with respect to stranded cost or other provisions contained in a non-public utility's open access tariff will involve the exercise of Commission jurisdiction over a non-public utility's open access

[24] As the market evolves, the Commission may need to take up a broad array of transmission pricing issues. It may well develop that a long-term solution to any problems raised by discounting requires fundamental changes to the transmission pricing methods currently in place in the electric industry.

[25] NRECA at 13–14; TDU Systems at 13–14.

[26] NEPOOL at 7.

[27] *Id.* at 7–8.

[28] TAPS at 22.

[29] *Id.* at 23 (footnote omitted).

[30] RUS at 10–11.

[31] *Id.* at 12.

transmission tariff as well as a determination of the legitimacy of the non-public utility's stranded cost claims.'' [32] RUS says that the Commission has not indicated that it will apply the comparability standard to the transmission rates that rural cooperatives charge members and non-members in a manner that will take into account the unique characteristics of a cooperative system, the inherent differences between members and non-members, and the intended beneficiaries of the RE Act.

Commission Conclusion. With respect to NRECA and TDU Systems' requested clarification of the deleted words ''in interstate commerce'' from section 6 of the pro forma tariff, we reiterate that transmission customers in the United States must provide reciprocal transmission service ''over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer.'' [33] Thus, a transmission customer must provide transmission service over *all transmission* facilities that it owns, controls or operates. This includes transmission facilities in both interstate and intrastate commerce. Such a customer, however, need not provide reciprocal service over facilities used solely in local distribution.

We recently addressed concerns similar to those raised by NEPOOL as to the applicability of the reciprocity condition to a Canadian utility selling power to a U.S. utility. In an order addressing Ontario Hydro's motion for a stay of the reciprocity provision of Order Nos. 888 and 888–A as those orders apply to transmission-owning foreign entities, we explained that the reciprocity condition does not apply

> in circumstances where a Canadian utility sells power to a U.S. utility located at the United States/Canada border, title to the electric power transfers to the U.S. border utility, and the power is then resold by the U.S. border utility to a U.S. customer that has no affiliation with, and no contractual or other tie to, the Canadian utility. The reciprocity provision thus does not in any way affect historical Canadian-United States buy-sell arrangements, *i.e.*, those involving sales to U.S. border utilities who then resell power to purchasers that have no contractual or other transactional link to the Canadian seller. For these types of historical sales, a Canadian seller is no worse off under Order Nos. 888 and 888–A than it was prior to the orders' issuance. Additionally, Order Nos. 888 and 888–A do not disrupt any pre-Order No. 888 power sales contracts under which Ontario Hydro sells to U.S. utilities, or any pre-Order No. 888 transmission contracts under which it purchases transmission from U.S. utilities.[34]

Thus, Order Nos. 888 and 888–A do not disrupt any existing agreements, as defined in those orders, between New Brunswick and any of its U.S. customers. Moreover, to the extent any of New Brunswick's transactions are buy-sell arrangements of the type described above, such transactions also are not affected by Order Nos. 888 and 888–A. However, if New Brunswick seeks to sell power under new agreements or through new coordination transactions, such transactions are subject to Order Nos. 888 and 888–A and New Brunswick would have to agree to provide reciprocal open access transmission, unless waived by the U.S. public utility or this Commission.

TAPS' rehearing request with respect to the safe harbor procedure was not timely filed. In Order No. 888, the Commission explicitly stated that ''we intend that reciprocal service be limited to the transmission provider.'' [35] The Commission also stated, in establishing the safe harbor procedure, that ''[w]e are aware that many non-public utilities are very willing to offer reciprocal access, and that some are willing to provide access to all eligible customers through an open access tariff.'' [36] Thus, it was clear that a non-public utility could meet reciprocity under the safe harbor procedure by agreeing to provide service only to the transmission provider or to any eligible customer. Nothing in Order No. 888–A changed this approach. The Commission's discussion of the safe harbor procedure in Order No. 888–A was limited to *Santee Cooper* [37]—a company-specific case decided subsequent to Order No. 888. The Commission noted that while the company in that case chose to offer an open access tariff to all eligible customers, ''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.'' [38]

We also disagree with TAPS' assertion that the Commission has taken ''an unnecessary step backwards from its expressed aim of remedying past undue discrimination and providing non-discriminatory open access.'' We explicitly stated in Order No. 888 our rationale for requiring that reciprocal access be offered only to the transmission provider from whom the non-public utility obtains open access service:

> 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.[39]

With respect to RUS' concerns regarding the availability of bilateral agreements, we clarify the distinction between the two different circumstances: (1) That of a *non-public* utility seeking transmission service from a public utility, and the requirement imposed on the public utility in providing the service; and (2) that of a *public* utility seeking transmission from a non-public utility, and what is sufficient for the non-public utility to provide reciprocal transmission service. As we stated in Order No. 888–A, if a *non-public* utility seeks service from a public utility, that public utility should, except in unusual circumstances, provide the service ''pursuant to the open access tariff and not pursuant to separate bilateral agreements.'' [40] On the other hand, if a *public* utility seeks service from a non-public utility through the reciprocity condition, Order No. 888–A provides that the non-public utility may provide that service pursuant to a bilateral agreement to satisfy its reciprocity obligation.[41]

We do not agree with RUS that public utilities will have no incentive to take service under bilateral agreements or to waive the reciprocity condition for non-public utilities. If a public utility needs transmission service from a non-public utility to maximize its profits or to make sales or purchases on behalf of its native load, then it should not care whether it takes service from the non-public utility under a bilateral agreement or an open access tariff. However, we recognize that even if the public utility does not need transmission service from a non-public utility, it may use the reciprocity condition as a reason to deny transmission service. But this is no different from the situation non-public utilities were in prior to the issuance of Order No. 888 when utilities could outright deny any transmission service. In that situation, the only recourse for the non-public utility was to file a request for service under section 211. The same is true post-Order No. 888.[42]

[32] *Id.*

[33] *See* FERC Stats. & Regs. at 30,513.

[34] Order Clarifying Order No. 888 Reciprocity Condition and Requesting Additional Information, 79 FERC ¶ 61,182 at (1997) (footnotes omitted); *see also* Order Denying Motion for Stay, 79 FERC ¶ 61,367 (1997).

[35] FERC Stats. & Regs. at 31,760.

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

[37] South Carolina Public Service Authority, 75 FERC ¶ 61,209 at 61,701 (1996).

[38] FERC Stats. & Regs. ¶ 31,048 at 30,289.

[39] FERC Stats. & Regs. ¶ 31,036 at 31,762.

[40] FERC Stats. & Regs. ¶ 31,048 at 30,285.

[41] *Id.* at 30,289.

[42] Of course, the flip side is equally true. If a public utility seeks service from a non-public

Continued

In any event, should a public utility refuse to provide transmission service based on a claim that the non-public utility requesting transmission service is not willing to provide reciprocal service, the non-public utility may always file a transmission tariff under the safe harbor procedure. We do not see this as any burden as the Commission has made available for interested entities a complete open access tariff that would require little modification to file.[43] Moreover, as we have explained, this reciprocal tariff, filed under the safe harbor procedure, need only be made available to the public utility (or utilities) from whom the non-public utility obtains open access transmission service. Further, if, as RUS seems to imply, the cooperatives do not want to provide *any* service, that is fundamentally at odds with the basic reciprocity provision and the fairness/competition concepts that underlie it.

We also reject RUS' argument that requiring a non-public utility to seek a waiver is inconsistent with the Commission's assertion that the reciprocity condition is voluntary. First, we did not require that non-public utilities seek a waiver, but merely provided a waiver as an option for them to pursue. Moreover, the waiver option (from the public utility or the Commission) is available only if a non-public utility *voluntarily* chooses to request open access transmission service from a public utility. As we explained in Order No. 888–A:

> 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.[44]

We will clarify for RUS that the Commission's statement that ''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'' does not apply to member distribution cooperatives when their G&T cooperative obtains open access transmission service. We did not intend this statement to change our position with respect to cooperatives and reaffirm our prior pronouncement 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.[45]

Finally, we disagree with RUS' claim that ''any comparability determination with respect to stranded cost or other provisions contained in a non-public utility's open access tariff will involve the exercise of Commission jurisdiction over a non-public utility's open access transmission tariff as well as a determination of the legitimacy of the non-public utility's stranded cost claims.'' [46] In Order No. 888–A, the Commission explained that a non-public utility that chooses voluntarily to offer an open access tariff for purposes of demonstrating that it meets the reciprocity condition can include a stranded cost provision in its tariff, but adjudication of any stranded cost claims under that tariff would not be subject to our jurisdiction. We said that although we would not determine the rate of a non-public utility (including the stranded cost component of the rate), ''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.'' [47] In reviewing a public utility's claims that a non-public utility is applying its stranded cost provision in a non-comparable (or discriminatory) manner, we would not be exercising jurisdiction over the non-public utility or its rates. We simply would be enforcing the reciprocity condition. As we said in Order No. 888–A, ''[i]t 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.'' [48]

3. Indemnification/Liability

Several petitioners argue that the Commission erroneously established a new standard of liability for transmission providers—simple negligence—that is contrary to the weight of authority in states across the country.[49] They claim that the Commission's standard would expose transmission providers and their native load customers to potentially enormous liability, including large consequential damage awards.[50] EEI also argues that the Commission has made no finding that a change in the standard is needed to remedy alleged undue discrimination nor, it argues, has the Commission demonstrated any reason to change the liability standard. According to EEI, the proper standard is ''gross negligence.''

Similarly, Puget argues that the Commission erroneously refuses to allow the express exclusion of consequential and indirect damages. It argues that the exception language in section 10.2 of the pro forma tariff (''except in cases of negligence or intentional wrongdoing by the Transmission Provider'') should be changed to ''except in cases of and to the extent of comparative or contributory negligence or intentional wrongdoing by the Transmission Provider.'' It further argues that Order No. 888 should be revised to exclude liability for special, incidental, consequential or indirect damages.

Coalition for Economic Competition states that the Commission erroneously relied upon a gas decision as a basis for adopting an ordinary negligence standard. It asserts that the characteristics of gas and electric service and the risks associated with each are very different: (1) the wires for electric transmission are located above ground and more susceptible to outages than buried pipelines and (2) the electric grid is more complex, with the potential for a single problem to affect a significant number of customers over a large geographic area. Thus, it argues, electric transmission providers face a much greater exposure to liability than gas transporters.

EEI and KCPL request that the Commission clarify whether states have authority to establish the scope of a utility's liability in providing federally mandated transmission service, as provided for in Order No. 888–A. Because of some uncertainty on this issue and the fact that 25 states do not have reported decisions on the issue, EEI indicates that there is likely to be significant litigation, which may lead to uncertainty between the parties to the

utility, the only way it may be able to seek such service is by filing a section 211 application.

[43] We note that since issuance of Order No. 888, ten non-public utilities have filed reciprocity tariffs, including cooperatives.

[44] FERC Stats. & Regs. ¶ 31,048 at 30,285 (emphasis in original).

[45] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,286. We note that this does not prevent an eligible entity from filing a section 211 request with a ''distribution'' cooperative.

[46] RUS at 12.

[47] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,364 n.527.

[48] *Id.* at 30,285.

[49] *See* KCPL and Coalition for Economic Competition. EEI also raises this issue, but EEI filed its request for rehearing out-of-time on April 4, 1997 with a request that the Commission accept the rehearing request because it has occurred at the very start of the proceeding, no response is required by any other party and there will be no prejudice to any other party. EEI failed to file its rehearing request within the 30 day period required by the Federal Power Act. *See* 16 U.S.C. 825l(a). Accordingly, we will not accept the rehearing request for filing, but will accept the pleading as a motion for reconsideration.

[50] *See* Coalition for Economic Competition, EEI.

interstate service transaction. If the Commission determines that states do not have authority, EEI and KCPL assert that the Commission should establish a rule of liability based on a standard of gross negligence. If the Commission determines that states do have the authority to establish the scope of a transmission provider's liability, EEI, as well as KCPL, assert that the Commission ''should clarify that states are preempted from attaching liability to actions taken by a transmission provider in compliance with the provisions of its filed pro forma tariff'' and ''should make an affirmative statement that it is expressing no opinion on whether a transmission provider should be liable, for public policy reasons, for acts of ordinary negligence.'' [51]

Coalition for Economic Competition further maintains that

> while the Commission directs transmission providers to rely on state law for protection against liability, it ignores the policies established at the state level which already address the issue. As a result, FERC is reallocating the risks associated with the transmission of electricity. To the extent that reallocation forces utilities to experience an additional financial burden, captive customers will be forced to pay more—more than the parties agreed would be their fair share. [[52]]

Furthermore, Coalition for Economic Competition states that case law may not protect the utility and its captive customers from the costs associated with the reallocation of risk:

> Frequently, the outcome of a case is closely related to any applicable tariff language that embodies that state's public policy as set by its regulatory commission. If the *pro forma* liability provision differs from the standards used in a particular state, the applicability and usefulness of that state's prior court decisions is unclear. [[53]]

Coalition for Economic Competition also asserts that the Commission appears to be sending contradictory signals, citing a recent decision (*New York State Electric & Gas Corporation*, 78 FERC ¶ 61,114 (1997)) in which the Commission rejected a provision in an open access tariff that acted as a choice of law provision. It argues that issues involving which jurisdiction provides the most appropriate forum, and which law should apply, are likely to be contested issues. In sum, Coalition for Economic Competition states that ''the Commission's reliance on state law leaves a wide open gap in which the outcome of potential claims is completely unknown, and the risk to which transmission providers are exposed is increased even more.'' [54]

Commission Conclusion. The tariff provisions on Force Majeure and Indemnification, as clarified in Order No. 888–A, provide certain limited protections to the transmission provider as well as its customers, when they faithfully attempt to carry out their duties under the tariff. The petitioners want the Commission to extend these limited protections to other situations or otherwise set forth definitive rules on liability in various situations that might arise under the tariff. We believe that the tariff provisions strike the right balance, and we will not here attempt to define the consequences of every conceivable breach that might occur under the tariff. Nor will we use the tariff, as some appear to want us to do, as an instrument for defining exclusive and preemptive federal laws for liability for all damages that might arise from the operation of the transmission system.

The Force Majeure provision of the tariff, in its essence, provides that neither the transmission provider nor the customer will be liable to the other when they behave in all respects properly, but unpredictable and uncontrollable force majeure events prevent compliance with the tariff. The Indemnification provision of the tariff, in its essence, provides that when the transmission provider behaves in all respects properly, the customer will indemnify the transmission provider from claims of damage to third parties arising from the service provided under the tariff. Under the terms of the tariff, the transmission provider may not rely on the protections provided by the Force Majeure clause or the Indemnification Clause for acts or omissions that are the product of negligence or intentional wrongdoing. Likewise, the customer may not rely on the protections provided by the Force Majeure clause for acts or omissions that are the product of negligence or intentional wrongdoing.

Contrary to the contention of EEI, the Force Majeure and Indemnification provisions do not establish a new simple negligence standard of liability for transmission providers. As we explained in Order No. 888–A, the issue of whether liability will attach to certain acts or omissions by a transmission provider is a different question from whether a customer should be obligated to indemnify the transmission provider in such circumstances.[55] In Order Nos. 888 and 888–A, the Commission has made no finding and expressed no opinion concerning whether a transmission provider should be held liable for damages to third parties arising from the transmission provider's acts or omissions of simple negligence, and the tariff language should not be construed as preempting the appropriate tribunal's consideration of whether liability should attach for acts or omissions of the transmission provider that injure third parties.

While the Commission has not established an exclusive and preemptive liability standard for electric utilities, EEI and the Coalition for Economic Competition would have us do so. They seek exculpatory language in the tariff that would protect the transmission provider from liability in all cases, except where gross negligence has been shown. Both acknowledge in their rehearing requests that such an exculpatory standard would in some regions alter the current liability standards, citing a study which concludes that 25 states have addressed the issue, with 21 of the 25 finding a gross negligence standard appropriate. Both argue that the Commission could eliminate potential uncertainties and conflicts among tribunals by determining a comprehensive and exclusive federal standard that accords with the determinations of the majority of states that have addressed this issue. EEI and KCP&L also question whether reference to state law is appropriate at all, suggesting that the Commission must develop a comprehensive federal standard of liability for service under the tariffs. We do not believe that such a determination is necessary or appropriate at this time.

First, we note that there is no question that the Commission has exclusive jurisdiction to determine the reasonableness of rates, terms, and conditions for the transmission of electric energy in interstate commerce.[56] Moreover, it is clear that state tribunals may not second-guess or collaterally attack Commission determinations of the reasonableness of filed rates, terms, and conditions.[57] On the other hand, it is likewise clear that the Commission's jurisdiction to consider disputes arising under jurisdictional tariffs does not as a matter of law preclude state courts from also entertaining such disputes in the

[51] EEI at 7; KCPL at 7–8.

[52] Coalition for Economic Competition at 7.

[53] *Id.* at 8.

[54] *Id.* at 9.

[55] FERC Stats. & Regs. ¶ 31,048 at 30,301.

[56] 16 U.S.C. 824b; *see, e.g.,* Nantahala Power & Light Company v. Thornburg, 476 U.S. 953, 963–66 (1986); FPC v. Southern California Edison Company, 376 U.S. 205 (1964); Public Utilities Commission v. Attleboro Steam & Electric Company, 273 U.S. 83 (1927).

[57] *See, e.g.,* Mississippi Power & Light Company v. Mississippi *ex rel* Moore, 487 U.S. 354, 374–75 (1988); Gulf States Utilities Company v. Alabama Power Company, 824 F.2d 1465, 1471–72, *amended,* 831 F.2d 557 (5th Cir. 1987).

appropriate circumstances.[58] In determining whether the Commission will exercise jurisdiction in such cases, the Commission is guided by the principles set forth in *Arkansas Louisiana Gas Company* v. *Hall.*[59] Application of these principles suggests the possibility that tribunals other than the Commission may be called upon to adjudicate disputes arising from service under the tariff.

With that background, the concerns expressed by EEI and KCP&L concerning the need for a uniform federal liability standard closely resemble the concerns addressed by the court in *United Gas Pipe Line Company* v. *FERC.*[60] In that case, the Commission had approved a tariff that limited a pipeline's liability to claims of ''negligence, bad faith, fault or wilful misconduct'' and the pipeline appealed, arguing that a uniform standard of liability should be established that was more protective of the pipeline. The court rejected the claim that there was a need for a uniform federal standard more favorable to the pipeline. As the court explained, ''uniformity of result is needed only to protect the federal interest, that is, only to exculpate [the pipeline] from contract liability in all cases not based on [the pipeline's] fault. Uniformity of exculpation beyond those cases is not a matter of federal concern'' because in such instances ''liability flows only from [the pipeline's] mismanagement.''[61] This same reasoning applies here. It is appropriate for the Commission to protect the transmission provider through the tariff provisions on Force Majeure and Indemnification from damages or liability that may occur when the transmission provider provides service without negligence, but to leave the determination of liability in other instances to other proceedings.[62]

4. Qualifying Facilities (QF)/Real Power Loss Service

NIMO and EEI[63] seek rehearing of the Commission's clarification in Order No. 888–A that a

> QF arrangement for the 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.[64]

NIMO argues that the Commission's clarification is inconsistent with the criteria for QF status under sections 3(17) and 3(18) of the FPA and the Commission's precedent. NIMO argues that the Commission has decided that a QF can only sell the net output of its facility without losing QF status. According to NIMO, allowing QFs to purchase Real Power Loss Service will result in QFs selling in excess of their net output at avoided cost.[65]

Finally, NIMO argues that if the Commission wishes to allow QFs to purchase power to compensate for line losses from third parties, and to include such power in their sales, it must do so only after a rulemaking in which it has noticed its intention to amend its QF regulations.[66]

Commission Conclusion. As a preliminary matter, we reject NIMO's argument that the Commission could only grant the clarification provided in Order No. 888–A after a rulemaking in which it noticed its intent to amend its QF regulations. All of the QF cases cited by NIMO in its rehearing request involve the Commission clarifying its rules in case-specific situations. For example, in *Occidental Geothermal, Inc.* (*Occidental*), the Commission was required to define the term ''power production capacity'' of a facility as that term was used in 18 CFR 292.204(a).[67] The Commission did so without issuing a notice of proposed rulemaking and seeking comments.

Moreover, the issue raised by NIMO and EEI is whether the Commission's clarification would result in a facility losing QF status, as defined in sections 3(17) and 3(18) of the FPA. The Conference Report on PURPA provides:

> The new paragraphs 17(C) and 18(B) of the definitions provide that the Commission shall determine, by rule, *on a case-by-case basis, or otherwise,* that a small power production facility or a cogeneration facility is a qualifying small power production facility or cogeneration facility, as the case may be.[68]

Accordingly, NIMO's argument that the Commission has improperly amended its PURPA regulations is wrong.

The substantive issue raised on rehearing is an issue of first impression.[69] In *Occidental, Turners Falls,* as well as in *Power Developers, Inc.,*[70] *Malacha Power Project, Inc.* (*Malacha*),[71] and *Pentech Papers, Inc.,*[72] the Commission found that QFs were permitted to sell only the net output of their power production facilities as measured at the point of interconnection with the electric utility to which they were interconnected. The Commission did not decide the question of whether ''the 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'' would be a sale-for-resale of power by a QF that would violate the Commission's QF rules.

At first glance, it would appear that Real Power Loss Service and ancillary services fall within the definition of ''supplementary power'' as defined in 18 CFR 292.101(b)(8).[73] If this were in fact the case, the precedent cited above would be relevant because supplementary power would be subtracted from gross output to determine the net output available for sale and, pursuant to *Turner Falls*, any sale in excess of the net output would result in a loss of QF status. However, if Real Power Loss Service and ancillary services are part of the costs of transmission, they are not covered

[58] *See, e.g.,* Pan American Petroleum Corporation v. Superior Court of Delaware, 366 U.S. 656, 662, 666 (1961).

[59] 7 FERC ¶ 61,175, *reh'g denied,* 8 FERC ¶ 61,031 (1979).

[60] 824 F.2d 417 (5th Cir. 1987).

[61] 824 F.2d 427.

[62] Some of the rehearing requests concerning indemnification/liability raise issues that previously were raised on rehearing of Order No. 888 and were addressed by the Commission in Order No. 888–A. *See* Coalition for Economic Competition argument that the circumstances of electric transmission require a different result than the gas pipeline cases and Puget arguments that the negligence language of the indemnification provision should be changed to reference comparative or contributory negligence and that the tariff should exclude transmission provider liability for special, incidental, consequential, or indirect damages. The Commission will not further address such issues in this proceeding.

[63] As discussed above, EEI filed its request for rehearing out-of-time. Accordingly, we are treating EEI's pleading as a motion for reconsideration.

[64] FERC Stats. & Regs. ¶ 31,048 at 30,237 (1997). *See also* Puget.

[65] On April 21, 1997, Granite State Hydropower Association filed an answer to NIMO's rehearing request arguing that gross sales are permissible for QFs. In the circumstances presented, we will accept the answer notwithstanding our general prohibition on allowing answers to rehearing requests. *See* 18 CFR 385.713(d).

[66] EEI supports NIMO's arguments.

[67] 17 FERC ¶61,231 (1981).

[68] H.R. Rep. No. 95–1750, Public Utility Regulatory Policies Act, 95th Cong. 2d Sess. 89 (1978) (emphasis added). *See also* Turners Falls Limited Partnership, 55 FERC ¶61,487 at 62,670 n.33 (1991) (*Turners Falls*).

[69] We note that other aspects of the ''net/gross'' issue are pending before the Commission in separate proceedings and will be addressed by the Commission in subsequent orders. *See* Connecticut Valley Electric Company, Inc. v. Wheelabrator Claremont Company, L.P., *et al.* (Docket Nos. EL94–10–000 and QF86–177–001); Carolina Power & Light Company v. Stone Container Corporation (Docket Nos. EL94–62–000 and QF85–102–005); and Niagara Mohawk Power Company v. Penntech Papers, Inc. (Docket Nos. EL96–1–000 and QF86–722–003).

[70] 32 FERC ¶61,101 (1985).

[71] 41 FERC ¶61,350 (1987).

[72] 48 FERC ¶61,120 (1989).

[73] Supplementary power is defined as ''electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.''

under the definition of ''supplementary power.''

As the Commission explained in its Notice of Proposed Rulemaking, Small Power Production and Cogeneration-Rates and Exemptions:

> The costs of transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. These costs are part of the costs of interconnection, and are the responsibility of the qualifying facility * * *. The electric utility to which the electric energy is transmitted has the obligation to purchase the energy at a rate which reflects the costs that it can avoid as a result of making such a purchase.[74]

This view was adopted by the Commission in Order No. 69, Small Power Production and Cogeneration Facilities, Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978.[75] There the Commission defined '''interconnection costs' as the reasonable costs of * * * transmission * * *.''[76] It is also consistent with the Commission's findings in 18 CFR 292.303(d) that if a QF transmits its output to an electric utility with which it is not interconnected, the rate for the purchase of such energy ''shall not include any charges for transmission.'' Thus, all that remains is to determine whether Real Power Loss Service and ancillary services are part of the costs of transmission.

Ancillary services as defined in Order Nos. 888 and 888-A are part of the costs of transmission services. In Order No. 888, we defined ancillary services as those services ''that must be offered with basic transmission service under an open access transmission tariff.''[77] We noted that these services are those ''needed to accomplish transmission service while maintaining reliability within and among control areas affected by the transmission service.''[78] Thus, there is no question that ancillary services are part of the cost of transmission and therefore are included among the interconnection costs a QF is responsible for.

Real Power Loss Service is an interconnected operations service.[79] It is thus not a service which a transmission provider is *required* to provide under its open access transmission tariff. Nevertheless, the Commission recognized that a transmission customer must make provisions for Real Power Loss. As the Commission noted, a customer ''cannot take basic transmission service without such a provision.''[80] As a result, we find that Real Power Loss Service is also a part of the cost of transmission and included among the interconnection costs a QF is responsible for.

Consistent with 18 CFR 292.303(d), however, a QF purchasing Real Power Loss Service shall have its purchase rate adjusted up or down consistent with 18 CFR 292.304(e)(4).[81] In other words, while a QF can never sell more power than its net output at its point of interconnection with the grid, its location in relation to its purchaser (and thus its losses) may be relevant in the calculation of the avoided cost which it is entitled for the power it does deliver to its electric utility purchaser. However, as explained above, the receipt of Real Power Loss Service or ancillary services is not a sale-for-resale of power. Rather, they are part of the costs of transmission which the QF must bear, in the absence of an agreement to share such costs with the transmitting utility.

5. Right Of First Refusal/Reservation Of Transmission Capacity

NRECA, TDU Systems and TAPS seek clarification that the rights of network customers to reserve capacity to serve their own retail load are comparable to a transmission provider's right to reserve transmission capacity for its retail native load. They point to language in Order No. 888–A that supports their interpretation, but note that other language concerning the Right of First Refusal (ROFR) mechanism seems to provide an advantage to transmission providers in serving their retail native load.

NRECA and TDU Systems argue that the Commission improperly allows a transmission provider to reserve capacity as needed to serve its existing native load customers, but the cooperative wholesale power or firm transmission customer has only a right of first refusal that requires it to match competing bids, which exposes it to matching an incremental rate or opportunity cost rate capped at the cost of system expansion. They assert that ''[t]o the extent the transmission provider is able to continue to provide service to its retail native load at average embedded transmission costs, so too should the network customer have the right to continued service at average embedded-cost rates, rather than at incremental-cost rates or opportunity-cost rates capped only at the cost of system expansion.'' [82] TDU Systems requests that the Commission clarify that

> the ROFR provisions allow an existing network customer to continue to reserve transmission capacity at rates that remain comparable to the transmission provider's service to its retail native load.[83]

Similarly, NRECA requests the Commission to clarify that

> firm transmission customers for which the transmission provider has a planning requirement are on an equal footing with the transmission provider's retail load in reserving transmission capacity. The Commission accordingly should clarify that the ROFR provisions allow existing firm transmission customers for which the transmission provider has a planning requirement to continue to reserve their existing transmission capacity at rates that remain comparable to the transmission provider's existing service to its retail native load.[84]

TAPS asks the Commission to clarify that

> its discussion of the rights of a transmission provider to reserve and reclaim capacity needed for native load growth apply with equal force to capacity needed for network customers for which the transmission provider is equally responsible for planning its system. The Commission should also clarify that the transmission provider's reclamation/reservation right cannot be used to withdraw capacity currently or reasonably forecasted to be used by a network customer.[85]

TDU Systems further requests that the Commission clarify the rate an existing transmission customer would have to match to retain its reservation priority. It requests that the Commission clarify that the customer need match only the undiscounted tariff rate of general applicability and not the highest rate the transmission provider is then collecting

[74] FERC Stats. & Regs., Proposed Regulations 1977–1981, ¶32,039 at 32,437 (1979). *See also id.* at 32,447 (costs of transmission constitute interconnection costs and must be borne by QF unless transmitting utility agrees to share them).

[75] FERC Stats. & Regs., Regulations Preambles 1977–1981, ¶30,128 (1980).

[76] *Id.* at 30,866. *See also* 18 CFR 292.101(b)(7).

[77] FERC Stats. & Regs., ¶31,036 at 31,705 (footnote omitted).

[78] *Id.*

[79] *Id.* at 31,709.

[80] *Id.*

[81] In Order No. 69, the Commission noted:

Subparagraph (4) addresses the costs or savings resulting from line losses. An appropriate rate for purchases from a qualifying facility should reflect the cost savings actually accruing to the electric utility. If energy produced from a qualifying facility undergoes line losses such that the delivered power is not equivalent to the power that would have been delivered from the source of power it replaces, then the qualifying facility should not be reimbursed for the difference in losses. If the load served by the qualifying facility is closer to the qualifying facility than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.

Order No. 69 at 30,885–86.

[82] TDU Systems at 6; NRECA at 5.

[83] TDU Systems at 7.

[84] NRECA at 7.

[85] TAPS at 33.

from any customer, *i.e.*, an incremental rate based on an upgrade for a particular customer.

Commission Conclusion. In Order No. 888–A, we addressed concerns raised by transmission providers that the right of first refusal may prohibit them from recalling capacity needed for native load growth, by clarifying that the transmission provider may reserve existing capacity for retail native load growth. While the Commission's conclusion in Order No. 888–A, in the context of the treatment of retail native load, is correct, a transmission provider may also reserve existing capacity for both its own wholesale native load growth and network customers' load growth. As the Commission originally explained in Order No. 888:

> 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.[86]

Accordingly, in order to allay the concerns of NRECA, TDU Systems and TAPS, we clarify that network transmission customers are afforded the same treatment as the transmission provider on behalf of native load (retail and wholesale requirements customers) in terms of the reservation of existing transmission capacity by the transmission provider.

Regarding NRECA's and TDU Systems' allegation that a transmission provider's right to reserve existing transmission capacity for its retail native load is superior to a firm transmission customer's right of first refusal, we note that it is not clear if NRECA and TDU Systems' argument pertains to network transmission customers or to point-to-point transmission customers. The right of a transmission provider to reserve existing transmission capacity on behalf of network transmission customers is discussed above. The reservation priority of transmission capacity for point-to-point transmission customers is different because point-to-point transmission customers do not undertake the same payment obligation as either network transmission customers or the transmission provider on behalf of native load customers. As the Commission explained in Order No. 888–A in the context of reservation of existing capacity:

> 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.[87]

Additionally, we note that a firm transmission customer may always elect to take network transmission service in lieu of point-to-point transmission service, thereby obtaining rights to reserve existing transmission capacity that are comparable to the rights of other network customers and the transmission provider on behalf of native load.

Furthermore, unless prohibited by the terms of the existing transmission customer's contract, there is nothing to prevent an existing point-to-point transmission customer from seeking to extend the term of its contract. An existing transmission customer may also enter into an additional agreement for point-to-point transmission service and reassign such capacity until needed or choose a service commencement date concurrent with the termination of its existing contract.

TDU Systems asserts that Order No. 888–A ''leaves unresolved whether the customer must pay the undiscounted rate of general applicability for tariff service at the time of conversion or the highest rate the transmission provider is then collecting from any customer,'' such as an incremental cost-based rate.[88] We clarify that the right of first refusal does not require an existing transmission customer to match the highest rate the transmission provider is then collecting from *any* customer. The highest rate collected from *any* customer may involve a different service than that service received by the existing customer, which may result in an inappropriate comparison. In this regard, the Commission stated in Order No. 888–A that the purpose of the right of first refusal is to be a tie-breaker and, therefore, the competing requests should be substantially the same in all respects.[89] Accordingly, we clarify that the existing transmission customer exercising its right of first refusal will be required to match the term of service requested by another potential customer and may be required to pay the transmission provider's maximum filed transmission rate. However, the rate must be for substantially similar service of equal or greater duration.

TDU Systems also asks whether the maximum rate that a customer must match in exercising its right of first refusal would include an incremental cost-based rate for an upgrade to a competing customer or if the customer is required to match only the undiscounted tariff rate of general applicability. The right of first refusal is predicated on an existing customer continuing to use its transmission rights in the *existing* transmission system. The right of first refusal acts as a tiebreaker to determine whether the competing eligible customer or the existing transmission customer gets the existing transmission capacity. Accordingly, the maximum rate for such *existing* transmission capacity would be the just and reasonable transmission rate on file at the time the customer exercises its right of first refusal.[90]

In conclusion, we believe that we have struck an appropriate balance between our goals of: (1) Protecting the rights of retail and wholesale native loads and network customers by allowing the transmission provider to reserve existing transmission capacity for their projected load growth and (2) providing existing firm transmission customers with a priority over new requests for firm transmission service to continue receiving transmission service from existing transmission capacity when there is insufficient existing capacity available to accommodate all requests for transmission service.

6. Energy Imbalance Service

a. Appropriate bandwidth for small utilities. APPA argues that the Commission's revision in Order No. 888–A to the deviation bandwidth did not go far enough and does not address the requirements of *all* small utilities, *i.e.*, utilities that sell no more than 4 million MWh annually.[91] It asserts that the Commission has adequately remedied the problem for those small utilities serving load with a peak demand of less than 20 MW, but not for those utilities serving loads with greater peak demands.

To remedy the problem, APPA asks the Commission to revise the minimum

[86] FERC Stats. & Regs. ¶ 31,036 at 31,694 (emphasis added).

[87] FERC Stats. & Regs. ¶ 31,048 at 30,220.

[88] TDU Systems at 8.

[89] FERC Stats. & Regs. ¶ 31,048 at 30,197.

[90] Depending on the rate design on file for the existing capacity, a customer exercising its right of first refusal could face an average embedded cost-based rate, an incremental cost-based rate, a flow-based rate, a zonal rate, or any other rate design that the Commission may have approved under section 205 of the FPA.

[91] APPA at 21–23 (citing Blue Creek Hydro, Inc., 77 FERC ¶ 61,232 at 61,941 (1996), in which the Commission used the 4 million Mwh level for determining small utilities eligible for waiver of the requirements of Order No. 889).

bandwidth to provide a minimum deviation bandwidth of 2 MW for utilities serving load with a peak demand of less than 20 MW, 5 MW for utilities serving load less than 100 MW, and 7.5 MW for all other small utilities.

Commission Conclusion. We deny APPA's motion for reconsideration.[92] As the Commission explained in Order No. 888–A, the deviation bandwidth was developed ''to promote good scheduling practices by transmission customers. It is important that the implementation of each scheduled transaction not overly burden others.'' [93] The Commission reaffirmed its use of the 1.5 percent energy imbalance bandwidth as ''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.'' [94] However, the Commission recognized the needs of small customers and raised the minimum energy imbalance from one megawatthour per hour to two megawatthours per hour. In doing so, the Commission sought to balance its primary goal of promoting good scheduling practices with its commitment to provide as much relief as possible to small customers. Larger minimum deviation bandwidths, as proposed by APPA, could only unnecessarily jeopardize this balance at the expense of good scheduling practices.

Moreover, in Order No. 888–A, the Commission provided all customers, including small customers, further options to deal with any difficulties that may be experienced as the result of the minimum deviation bandwidth set forth in Order No. 888–A:

> 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.[95]

APPA has simply not shown that the minimum deviation or the procedures to reduce or avoid energy imbalance charges or to negotiate another bandwidth do not provide adequate relief for small customers. Nor has APPA shown that larger bandwidths could be implemented without unduly undermining good scheduling practices.

b. Settlements establishing a deviation bandwidth or minimum imbalance. TDU Systems states that Order No. 888–A allows a transmission provider and a customer to negotiate and file another bandwidth more flexible to the customer on a not unduly discriminatory basis, but if a settlement was approved subject to the outcome of Order No. 888, it must be revised in the subsequent compliance filing to reflect the language in the pro forma tariff. Accordingly, TDU Systems seeks clarification that if such a settlement contains a bandwidth above 1.5% or a minimum imbalance above 2 MW, those amounts need not be revised downward to conform to the pro forma tariff.[96]

Commission Conclusion. We will not grant the clarification sought by TDU Systems. In Order No. 888–A, we explicitly stated that

> 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.[97]

This is consistent with our desire to have all public utilities at the same starting line as open access is implemented in the electric industry:

> By initially requiring a standardized tariff, we intend to foster broad access across multiple systems under standardized terms and conditions.[98]

However, as we also recognized, ''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.'' [99] Thus, the settlement discussed by TDU Systems must be revised to conform to the pro forma tariff, but the public utility transmission provider to the settlement may then make another filing with the Commission to seek a change to the bandwidth contained in the pro forma tariff.

7. Transmission Provider ''Taking Service'' Under Its Tariff for Power Purchased on Behalf of Bundled Retail Customers

a. Jurisdiction. IL Com states that the Commission agreed with IL Com's jurisdictional arguments on rehearing of Order No. 888 and made the following appropriate clarifications in Order No. 888–A:

> In a situation in which a transmission provider purchases power on behalf of its retail native load customers, the Commission [FERC] *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. [quoting Order No. 888–A at 117–18 (emphasis added)].
>
> * * * * *
>
> [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. [quoting Order No. 888–A at 118 (emphasis added)].[100]

However, IL Com argues that the Commission

> nevertheless neglected to revise § 35.28(c)(2) and § 35.28(c)(2)(i) to incorporate these clarifications into the Rule. Therefore, [IL Com] reiterates its request that the words ''for sale for resale'' be inserted into the Rule after the word ''purchases'' in § 35.28(c)(2) and ''purchase'' in § 35.28(c)(2)(i) to codify the Order 888–A clarification concerning the extent of required power purchase unbundling.[101]

CCEM, however, argues that the Commission's disclaimer of jurisdiction over the transmission in interstate commerce of purchased power headed for retail customers is contrary to the FPA's assertion of jurisdiction over all transmission of electric energy in interstate commerce.[102] It states that

> [t]he Commission has already embraced the proposition that it has the statutory authority and mandate to require utilities to adopt tariffs that will ensure all market participants comparable access to transmission services. It must now extend that authority and mandate to apply to all transmission service.[103]

CCEM further argues that the Commission's failure to assert jurisdiction over interstate transmission of purchased power to retail customers is contrary to precedent under the Natural Gas Act (NGA).[104] It cites to *Mississippi River Transmission Corp*. v. *FERC*, 969 F.2d 1215 (D.C. Cir. 1992), stating that the court affirmed the Commission's interpretation of NGA section 1(b) as authorizing the Commission to regulate the price of natural gas transportation service that

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[92] As discussed above, APPA filed its request for rehearing out-of-time. Accordingly, we are treating APPA's pleading as a motion for reconsideration.

[93] FERC Stats. & Regs. ¶ 31,048 at 30,232.

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

[95] *Id*.

[96] TDU Systems at 12–13.

[97] FERC Stats. & Regs. ¶ 31,048 at 30,233.

[98] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,734.

[99] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,234 (footnote omitted).

[100] IL Com at 8.

[101] *Id*. at 8–9.

[102] CCEM at 2–6.

[103] *Id*. at 4.

[104] *Id*. at 4–6 (citing Mississippi River Transmission Corp. v. FERC, 969 F.2d 1215 (D.C. Cir. 1992)).

MRT provided in support of certain firm direct sales.

If the Commission does not grant rehearing as requested by CCEM, CCEM argues that ''the Commission should nevertheless clarify that its jurisdictional disclaimer does not extend to power pool transmission services.'' [105] It asserts that because pools themselves do not have native load and do not purchase power on behalf of native load, ''when a public utility takes poolwide service to transmit purchased power, it should be required to take that service on an unbundled basis pursuant to the power pool's open-access tariff.'' [106] In this regard, it states that it is ''aware that certain public utilities claim that the Commission's disclaimer of jurisdiction extends to their uses of poolwide transmission service to transmit purchased power to their captive, native loads.'' [107]

CCEM further argues that the Commission's failure to require that all transmission service be taken under an open access tariff is arbitrary and irreconcilable with the Commission's concurrent determination in connection with the rules pertaining to stranded cost recovery that it has jurisdiction over the rates, terms and conditions of unbundled interstate transmission services by public utilities to retail customers, and that it has the authority to address retail stranded costs through its jurisdiction over such services. It adds that experience from restructuring the natural gas industry (Order Nos. 436 and 636) shows the need to unbundle and separately regulate transmission provided in connection with retail service.

Commission Conclusion. CCEM's arguments with respect to the Commission's disclaimer of jurisdiction over bundled retail transmission are the same arguments it raised on rehearing of Order No. 888 (and were addressed by the Commission) [108] or should have raised on rehearing of Order No. 888. We will not accept CCEM's invitation to further address this issue.

In response to CCEM's request for clarification regarding power pool transactions, we note that all power pool transactions must be taken under the terms of the pool-wide pro forma tariffs that were filed on compliance to Order No. 888.[109] The appropriateness of the terms and conditions contained in those pool-wide pro forma tariffs will be addressed on a case-by-case basis when the Commission addresses the merits of the various pools' compliance filings.

Finally, we deny IL Com's request to modify sections 35.28(c)(2) and 35.28(c)(2)(i) of the Commission's regulations. The additional language proposed by IL Com simply will not work. As we describe in more detail in section 7.b below, it is not possible, as a practical matter, to divide a single power purchase made on behalf of both wholesale and retail native load such that the transmission provider takes service under the terms and conditions of the pro forma open access transmission tariff for the wholesale part of the purchase and under the terms and conditions of a different tariff for the retail part. Thus, the entire purchase transaction must be undertaken pursuant to the terms and conditions of the pro forma open access transmission tariff. The language proposed by IL Com does not recognize the indivisible nature of single power purchases made on behalf of both wholesale and retail native load.

b. Purchases for retail native load. TAPS argues that the Commission significantly contracts its functional unbundling requirement and the associated Standards of Conduct ''by exempting from functional unbundling all use by a transmitting utility of its own transmission system to serve bundled retail native load.'' [110] By exempting a key aspect of the transmission provider's activities in wholesale markets from the open access rules, TAPS asserts, comparability is destroyed and the market is severely distorted. It emphasizes that

> because of the interdependence, elasticity and fungibility of purchases on behalf of unbundled retail load with the transmission provider's other wholesale marketing activities, there is little, if anything, left of functional unbundling.[111]

TAPS states that Order No. 888–A leaves unclear issues critical to comparability, ''such as request procedures and priority for usage of limited interface capability applicable to the transmission provider's use of transmission for economy imports for retail bundled load.'' [112] It argues that without clearly established rules that put the transmission provider in the same position as network customers, the transmission provider will have a competitive advantage.

TAPS further argues that the Commission's approach defeats the Commission's Standards of Conduct and allows transmission provider employees involved in the transmission function to ''share operational and reliability information with employees engaged in making economic and other purchases for retail bundled load on a preferential basis as compared with other transmission customers or the transmission provider's 'wholesale' merchant function.'' [113] Further, it asserts that the Commission's approach to functional unbundling will encourage a transmission provider to retain its preferential access to transmission service and information and discourage it from joining an ISO, under which it would lose its preferential treatment.

TAPS concludes by arguing that ''[c]ontrary to the Commission's suggestion, constriction of functional unbundling is not required by limitations on the Commission's jurisdiction.'' [114] It asserts that the Commission has provided no support for its position and adds that the Commission's position cannot be reconciled with its treatment of transmission agreements between jurisdictional and non-jurisdictional entities whereby the Commission stated that its authority over a jurisdictional contract involving a public utility cannot be impaired by virtue of the fact that the other party is non-jurisdictional.

Commission Conclusion. While we have reiterated our view that the Commission does not have jurisdiction over the rates, terms and conditions of *bundled* retail service, based on the comments received on rehearing, we believe certain clarifications need to be made. As a practical matter, we do not believe that it is possible to divide a *single* power purchase made on behalf of both wholesale and retail native load such that the transmission provider takes service under the open access non-rate terms and conditions for the part of the purchase that goes to wholesale native load, but takes service under different terms and conditions for the part of the purchase that goes to retail native load. Because the power purchase transaction (including the delivery across the transmission provider's system to both wholesale and retail customers) is indivisible, and because the transmission of the purchased power to the wholesale native load customer must be done

[105] *Id. at 6.*

[106] *Id.*

[107] *Id.*

[108] FERC Stats. & Regs. ¶ 31,048 at 30,225–26.

[109] *See* MidContinent Area Power Pool, et al., 78 FERC ¶ 61,203 (1997) (Order Accepting for Filing and Suspending Proposed Pool-Wide and Single-System Holding Company Open Access Transmission Tariffs and Revised Tariffs, and Deferring Further Action), *reh'g pending.*

[110] TAPS at 4 and 6–14.

[111] *Id.* at 5.

[112] *Id.* at 9.

[113] *Id.* at 10–11.

[114] *Id.* at 14.

pursuant to the open access tariff, this means that the entire transaction *de facto* must be pursuant to the non-rate terms and conditions of the tariff.

Concerning the Standards of Conduct requirement that public utilities separate their *wholesale* power marketing functions from their transmission operations, the Commission did not require separation of the *retail* power marketing function because the state has jurisdiction over retail power marketing and over bundled retail transmission. However, here too we believe further clarification is necessary. First, the public utility has no choice pursuant to Order Nos. 888 and 888–A but to separate its wholesale power marketing function (including power purchase transactions made by the marketing function on behalf of wholesale native load) from the transmission operations function. This means that those persons in the company that are involved in wholesale power purchases as well as wholesale sales cannot interact with the transmission personnel other than through the OASIS. Thus, to the extent they are making purchases on behalf of wholesale as well as bundled retail native load as part of a single purchase, they will have to abide by the separation of function requirement. As discussed above, such a purchase is not divisible. Additionally, it is conceivable that there could be a separate retail marketing function for native load and a separate wholesale marketing function for native load. If a challenge is made to the way a utility organizes its functions, then the utility bears the burden of demonstrating that it is maintaining a separate staff to perform retail marketing functions. Furthermore, in such cases, it would clearly be inappropriate for the retail staff to share transmission information with the wholesale marketing staff.

8. Indirect Unbundled Retail Transmission in Interstate Commerce

Referencing the Commission's conclusion that section 212(h) does not prohibit the Commission from ordering public utilities to provide indirect unbundled retail transmission in interstate commerce, BPA states that it appears that the Commission intended to clarify its jurisdiction to order retail transmission in certain limited, interstate situations—namely, to ensure that state initiatives would not be frustrated by the failure of neighboring states to undertake similar initiatives. Where a state has not mandated retail access, but a local utility agrees to provide retail access,[115] BPA argues that it should not be required to distribute another supplier's power to its customers.

BPA also argues that section 212(h)(2) prohibits orders requiring ''indirect retail transmission.'' It declares that the Commission ignored section 212(h)(2), which it asserts prohibits orders requiring indirect retail transmission. BPA contends that, if it and other transmitting utilities are required to provide indirect retail transmission, BPA's ability to meet its statutory obligation to recover all of the costs of the Federal Columbia River Power System and the Commission's ability to meet its statutory obligation to ensure that BPA's rates are sufficient to assure repayment of the federal investment in the power system will be placed at risk.

Commission Conclusion. We disagree with BPA that we ignored section 212(h)(2) in concluding that we have the authority to order indirect retail transmission in interstate commerce to accommodate retail access programs ordered by a state or voluntary retail delivery by the local utility. We clarify that while section 212(h)(2) may limit the Commission in certain circumstances, as a general matter, we believe we can order indirect interstate transmission services necessary to accommodate direct retail access programs that are state ordered or voluntary. Clearly, whether section 212(h) would prohibit the Commission from ordering transmission in a particular circumstance would depend upon the facts presented, including who the transmission requestor is, who the seller of energy is, and who is transmitting or delivering the energy and over what facilities. If parties wish to raise section 212(h)(2) in a particular case, they may do so; however, we do not believe Congress intended section 212(h)(2) to be used as a competitive shield against state-ordered retail access programs or voluntary retail access by local utilities.[116]

9. Mobile-Sierra

Met Ed objects to what it describes as the Commission's asymmetric treatment of customers and suppliers in Order No. 888–A. First, it argues that the existence of uneven bargaining power prior to Order No. 888 (that is referred to in Order No. 888–A) does not provide a rational basis for imposing different standards for customer-initiated and supplier-initiated requests for modification of existing contracts. It says that the Commission does not identify the specific manner in which existing wholesale contracts would lose their just and reasonable character due to changes in the electric industry. ''Just as competitive wholesale markets may present opportunities to buyers that are less costly than existing contracts, they may also give sellers greater opportunities to reach new buyers who would be willing to pay more than customers under existing below-cost contracts. If the Commission's initiatives to expand wholesale markets provide a rational basis for making it easier for buyers to modify existing contracts, then these initiatives equally provide a basis to ease the burden on sellers.''[117]

Second, Met Ed argues that because the existence of uneven bargaining power was not universal, it cannot provide the basis for a uniform refusal to apply a just and reasonable standard in evaluating all supplier-initiated requests for modification (other than of stranded cost provisions). ''The Commission cannot properly distinguish customers from suppliers based on a premise that is only true in the 'majority' of the cases, particularly when the Commission has the ability to make the appropriate determination on a case-by-case basis.''[118]

Third, Met Ed says that the Commission's distinction between customers and suppliers is not rationally related to the purpose of Order No. 888. It contends that broad competition is not furthered by a policy that would hold suppliers, but not customers, to the terms of existing unfavorable contracts. Met Ed states that ending the subsidies reflected in long-term below-cost contracts promotes the most efficient use of power supply resources. According to Met Ed, Order No. 888-A's treatment of existing contracts will exacerbate stranded costs (a utility would not be able to obtain relief from a wholesale contract that does not cover its costs, while a customer under another contract could obtain a modification or termination of the contract). ''Even if the Commission persists in its conclusion that it can reasonably distinguish requests for modifications by customers from those by utilities because existing contracts

[115] *See also* Puget at 27.

[116] BPA's arguments that requiring indirect retail wheeling may put at risk its ability to meet its statutory obligation to recover all of the costs of the Federal Columbia River Power System and the Commission's ability to meet its statutory obligation to ensure that BPA's rates are sufficient to assure repayment of the federal investment in the power system are speculative and more appropriately addressed in a fact-specific proceeding if and when this possible risk may arise. Moreover, BPA may propose appropriate stranded cost provisions.

[117] Met Ed at 6.

[118] *Id.* at 7.

reflect one sided bargaining, it should clarify that it will not make such a distinction when customers had other options at the time the contracts were executed.''[119]

Commission Conclusion. Met Ed has not raised issues not previously addressed by the Commission. Concerning its argument that uneven bargaining power was not universal, Order No. 888 clearly recognized that this was the case.[120] However, we clarify that, in determining whether to modify an existing contract, we will look at, among other things, whether a customer had other supply options available to it at the time it negotiated its existing contract. We agree with Met Ed that the existence of uneven bargaining power may not have been ''universal'' and clarify that utilities are free to present to the Commission, on a case-by-case basis, arguments that their contracts are no longer in the public interest or just and reasonable, and therefore should be modified.

10. Tariff Issues

a. Load served ''behind-the-meter.'' Central Maine states that the Commission required all of a wholesale network customer's load ''behind-the-meter'' to be included in its load-ratio share. It asserts, however, that the Commission ''failed to state whether the utility also must include all of a retail customer's load 'behind-the-meter' in computing the load-ratio share.'' [121] It indicates that it is concerned that it cannot identify the ''behind-the-meter'' generation that its retail customers own and operate. Central Maine maintains that ''[o]nly if the utility invests significant effort and incurs substantial expense to install metering technology will it have the ability to monitor its retail customers.'' [122] In any event,

Central Maine believes that the Commission did not intend to require utilities to determine their retail customers ''behind-the-meter'' load when calculating network customers' load-ratio shares. Moreover, the Commission cannot require a non-jurisdictional wholesale customer to determine its retail customers ''behind-the-meter'' load. Thus, if FERC required jurisdictional companies to make such a determination, the load-ratio share of network non-jurisdictional wholesale customers would always be understated. The Commission should clarify Order No. 888–A so that it is clear that utilities are not required to meter retail customer's ''behind-the-meter'' load.[123]

Commission Conclusion. Central Maine's concern regarding the identification of a retail customer's ''behind-the-meter'' generation and load is unclear. The Commission's discussion in Order Nos. 888 and 888–A regarding the treatment of behind-the-meter generation and load specifically pertained to an individual network customer's designated network generation and load. If Central Maine's concern pertains to the calculation of a transmission provider's total network load, including the load of the transmission provider's retail native load customers, such an inquiry is beyond the scope of Order Nos. 888 and 888–A and should be addressed on a case-by-case basis.

b. Definition of ''Native Load Customers.'' Dairyland argues that the definition of ''Native Load Customers'' in section 1.19 of the pro forma tariff is limited to wholesale and retail *power* customers and ''could be read not to encompass the native loads of parties to transmission joint use and construction agreements but who are not *power* customers of the Transmission Provider.'' [124] It proposes that the following clause be added to the end of section 1.19: ''including obligations arising from transmission joint use agreements in effect as of July 9, 1996.'' [125] Dairyland argues that the Commission should recognize these agreements and modify the definition so that ''transmission facilities constructed and operated to meet the reliable electric needs of each party's native load customers are treated comparably, without regard to whether either party is or is not a 'power' customer of the other.'' [126] It further indicates that its primary concern in seeking this modification is in terms of priority under the pro forma tariff for curtailment and reservations and believes that its status and rights are unclear.

Commission Conclusion. We believe that Dairyland's argument is misplaced and deny its request for rehearing. In *Allegheny Power Systems, Inc., et al.,*[127] we found that Dairyland's joint use agreements ''are in the nature of bilateral transmission agreements and are not superseded or otherwise affected by Interstate Power's compliance tariff. Thus, any changes to the definition of 'native load customers' are not necessary.'' [128] Accordingly, any change to the definition of native load customers contained in the pro forma tariff would have no affect on Dairyland's joint use agreements.

We also note that Dairyland has stated that under its joint use agreement ''the native loads of Dairyland and the native loads of the public utility party to the agreement were to be treated comparably in terms of transmission service utilizing the transmission facilities.'' [129] Thus, Dairyland already is obtaining the comparable treatment that it is apparently seeking through its proposal to change the definition of native load contained in the pro forma tariff.

c. Schedule changes. NRECA states that Order No. 888–A provided that schedule changes for firm point-to-point service were not limited up to twenty minutes before the start of each clock hour, but could be set at a reasonable time limitation that is generally accepted in the region and consistently adhered to by the transmission provider. NRECA requests rehearing to not only permit, but also to require, scheduling changes during emergency conditions.[130] It asserts that the Commission should make this revision consistent with the language of section 30.4 of the pro forma tariff that permits network resources to be rescheduled in response to an emergency or other unforeseen condition. In any event, if ''schedule changes are not permissible in such situations, at least any associated penalties, *e.g.*, punitive charges for energy imbalances exceeding the 1.5% 'deadband,' should be waived.'' [131]

Commission Conclusion. We deny NRECA's rehearing request to require transmission providers to make schedule changes requested by customers during emergency conditions. It is the responsibility of transmission customers to make arrangements for emergencies, such as operating reserves for the loss of a power supplier's generation source. If an emergency

[119] *Id.* at 10.

[120] *See, e.g.*, FERC Stats. & Reg ¶ 31,048 at 30,193.

[121] Central Maine at 2.

[122] *Id.* at 3.

[123] *Id.*

[124] Dairyland at 4 (emphasis in original).

[125] Dairyland notes that it filed a supplemental rehearing request on this issue that the Commission accepted as a motion for reconsideration. It asserts that the Commission did not address its issue in Order No. 888–A, but instead described the arguments as being similar to an argument it rejected that joint planning is a sufficient criterion to be considered a ''Native Load Customer'' and that construction and operation by the transmission provider should not be necessary for native load status to be conferred.

[126] *Id. at 6.*

[127] 80 FERC ¶ 61,143 at 61,555 (1997).

[128] We further note that Interstate Power Company did not file on December 31, 1996, as provided in Order No. 888, to modify its joint use agreements with Dairyland. *See* 18 CFR 35.28(c)(1)(iii). Thus, those agreements must not prohibit transmission over the facilities to third parties and, accordingly, remain in effect as existing bilateral transmission agreements.

[129] Dairyland at 6.

[130] *See also* TAPS at 35–36; TDU Systems at 24–25.

[131] NRECA at 16; *see also* TAPS at 36–37.

arises, a transmission provider should not be required to accept a customer-requested schedule change, though we would expect the transmission provider to permit a schedule change to the extent possible. Granting NRECA's request would ignore the fact that requiring the transmission provider to accept a requested scheduling change may not be consistent with maintaining system reliability.

Moreover, an emergency situation does not automatically cause a customer to use Energy Imbalance Service or to pay a penalty. For example, if a customer resource becomes unavailable due to an emergency situation, but is replaced by an equivalent amount of reserves, the customer would remain in balance if its load meets the schedule.[132] However, if the emergency is the cause of the customer's energy imbalance, that is, the transmission provider is unable to deliver the scheduled energy, the customer should not be responsible for paying an Energy Imbalance Service penalty.

d. Restriction on making firm sales from designated network resources. NRECA argues that section 30.4 of the pro forma tariff unreasonably restricts network customers' ability to make firm sales from their generation and that similar restrictions do not apply to transmission providers' own generation resources.[133] It asserts that this restriction on network customers ''is unnecessarily limiting both the number of competitors and the array of generation products available, as well as skewing the market in favor of generation sales by incumbent public utility transmission providers.'' [134] If the Commission does not change its position, NRECA states that the Commission should at least provide network customers greater flexibility in designating network resources under section 30.1 of the pro forma tariff:

> the Commission should at least grant network customers the ability to designate network resources over shorter time periods (*e.g.*, one month) or permit the network customer to designate its network resources in a manner that varies by season or by month to track projected variations in network loads plus reserve requirements. This would provide network customers more flexibility in using their network resources to make firm off-peak sales to loads other than their network loads when it makes economic sense to do so, while still ensuring that adequate resources are committed to meet the network load and reserve requirements of the period.[135]

TDU Systems adds that if the Commission does not change its position, ''transmitting utilities should be required to designate their network resources, and those resources, too, should be restricted to serving the transmitting utilities' network loads.''[136]

Commission Conclusion. We disagree with NRECA, as well as TDU Systems, that the restrictions set forth in section 30.4 of the pro forma tariff do not also apply to a transmission provider's own generation resources. In Order No. 888, we explicitly stated that

> a transmission provider taking network service to serve network load under the tariff also is required to designate its resources and is subject to the same limitations required of any other network customer.[137]

In addition, we note that, contrary to NRECA's assertion, the pro forma tariff does not prevent network customers from designating network resources over shorter time periods or in a manner that varies by season or by month. It only prohibits network customers from making sales from *designated* network resources. The purpose of the prohibition is to ensure that such resources are available to meet the network customer's network load on a non-interruptible basis. Sections 30.2 and 30.3 of the pro forma tariff already provide network customers with a significant level of flexibility. Specifically, a network customer that seeks to engage in firm sales from its current designated network resources may terminate the generating resource (or a portion of it) as a network resource and request, as set forth in section 29 of the pro forma tariff, that the same generation resource be designated as a network resource effective with the end of its power sale. We note that network customers, as well as the transmission provider's merchant function, must obtain point-to-point transmission service for off-system sales.

e. Reactive Power. NY Com states that under Order No. 888–A ''a transmission customer may satisfy part of its obligation [to supply reactive power service] through self-provision or purchases from generating facilities under the control of the control area operator.'' [138] It requests clarification that the phrase ''under the control of the control area operator'' refers only to generators with continuously operating automatic voltage control (AVC). NY Com argues that units that do not have AVC and operate ''flat out'' do not support reliability and increase operating difficulty and inflict higher costs because system operators need to monitor local voltage levels and anticipate changing reactive support requirements.

The Independent Power Producers of New York, Inc. (NY IPPs) responds to NY Com's request that only generators with continuously operating AVC be allowed to self supply reactive power.[139] It asserts that ''[t]here is no reason to suppose that the Commission intended that suppliers of reactive power without AVC should not receive credit for the service they render.''[140] It claims that NY Com's assertion that generators that do not have AVC and operate flat out cannot supply reactive power without inflicting higher costs on the system ''shows a fundamental misunderstanding of the operations of an electric generator.'' [141] It maintains that

> [t]he ability to provide reactive support at full power output without imposing higher system costs has nothing to do with whether a generator has AVC. Rather, the ability to provide reactive power support stems from the design of the generator itself, specifically the rating of the rotor and stator windings. The NYPSC's assertion that providing reactive support manually ''increases operating difficulty and inflicts higher costs because system operators need to actively monitor local voltage levels, and anticipate changing local voltage levels'' is both unsupported and irrelevant.[142]

Moreover, it asserts that ''[t]o the extent that generators with AVC that self provide reactive support render a more valuable service than those that self provide reactive support without AVC, they should be credited accordingly—but that does not mean that generators without AVC should not be credited at all for self providing reactive support.'' [143] In addition, NY IPPs responds to NY Com's assertion that it has discouraged the practice of manual voltage support by requiring non-utility generators to either use AVC or pay a fee based on the absorption of reactive power. It states that NY Com's requirement ''that non-utility generators *pay* a utility when the generator *absorbs reactive power at the utilities' request* is

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[132] *See* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,233 (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).

[133] *See also* TDU Systems at 18–21.

[134] NRECA at 17; *see also* Dairyland at 8.

[135] NRECA at 18.

[136] TDU Systems at 21.

[137] FERC Stats. & Regs. ¶ 31,036 at 31,753–54.

[138] NY Com at 15–16.

[139] On April 11, 1997, NY IPPs filed an answer to the request for clarification of NY Com. In the circumstances presented, we will accept the answer notwithstanding our general prohibition on allowing answers to rehearing requests. *See* 18 CFR 385.713(d).

[140] NY IPPs at 3.

[141] *Id.*

[142] *Id.* at 3–4.

[143] *Id.* at 4.

currently the subject of litigation in the United States District Court for the Northern District of New York.'' [144]

TAPS is concerned that without specific tariff language some transmission providers will try to deny reactive power credits to transmission customers that should otherwise receive such credits. It suggests that the following language should be added to the pro forma tariff:

> The service agreement of the transmission customer that can supply at least a part of the reactive service it requires, either through self-supply or purchases from a third party, shall specify the generating sources made available by the transmission customer that provide reactive support.[145]

TAPS also asks the Commission to clarify that the phrase ''under the control of the control area operator'' refers to ''the reactive production or absorption capability of the generator and not necessarily to the generator's ability to produce real power.'' [146] It states that

> while a generator's real power output may be on automatic generation control (AGC) and dispatched economically, its reactive power output usually is not on automatic control or dispatched on a moment-by-moment basis. Rather, the plant operator separately regulates the output of the two kinds of power. As a result, a customer can give the control area operator the ability to rely upon the customer's generation to produce or absorb reactive power independent of control over the unit's real power output, for example, by the customer's setting its generator's voltage regulator to respond to the needs of the control area as established by the control area operator. Thus, the Commission's statement that ''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,'' (Order No. 888–A at 150–51) should not be read to require that the entire generating unit be under the control area operator's control.[147]

Furthermore, TAPS argues that comparable standards should be applied to customer-owned and transmission provider facilities. ''The control area operator should not be permitted to refuse the offer of a customer to turn over to the control area operator the control of the reactive capabilities of the customer's generating facilities.'' [148] Moreover, it asserts that ''[i]f the control area operator is able to rely upon its own or its customer's facilities to produce or absorb reactive power, then rate base treatment or credits, respectively, are appropriate.'' [149]

Commission Conclusion. We do not agree with NY Com's assertion that the phrase ''generating facilities under the control of the control area operator'' refers only to generators with AVC. We clarify that what is ''under the control of the control area operator'' in Schedule 2 of the pro forma tariff is the reactive production and absorption capability of the generator and not the generator's ability to produce real power. With regard to the dispute between NY Com and NY IPPs concerning the appropriate reduction in charges for Reactive Supply and Voltage Controls from Generation Sources Service, we find that this dispute is fact-specific and beyond the scope of this proceeding.

There is no need to add the specific language to the pro forma tariff as requested by TAPS. As stated in Order No. 888–A, the Commission specifically requires that a transmission customer's service agreement specify all reactive supply arrangements, including the generating resources made available by the transmission customer that provide reactive support.

In response to TAPs' other concern, we note that Order No. 888 requires that a transmission customer obtain or provide ancillary services for *its* transactions. We do not intend that requirement to provide a means for a generation owner to compel a transmission provider to purchase services it may not need. As we stated in Order No. 888–A, 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.

f. Network Operating Agreements. TAPS asks that section 29.1 of the pro forma tariff be modified to permit a network customer to request that a network operating agreement be filed on an unexecuted basis, just as it may request a network service agreement to be filed on an unexecuted basis. It asserts that this would ''permit service to commence, pending resolution of disputed matters, and would reduce the ability of the transmission provider to use the network operating agreement as a competitive tool.'' [150]

Commission Conclusion. In Order No. 888–A, in response to TAPS' argument 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, we rejected mandating a particular network operating agreement but indicated that

> 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.[151]

On rehearing, TAPS points out that our approach would still permit a transmission provider to delay the commencement of service. We recognize this and will permit a network customer to request that a network operating agreement be filed on an unexecuted basis, just as we have allowed a network customer to request that a network service agreement be filed on an unexecuted basis. Accordingly, we will modify section 29.1 of the pro forma tariff by adding the following language to the end of section 29.1: '', or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.'' [152]

g. Network customers with loads and resources in multiple control areas. TDU Systems argues that Order No. 888–A does not respond to its ''core contention that network service under the pro forma tariff does not provide them comparable service.'' [153] It argues that

> [r]equiring the network customer to assign a designated network resource to a single control area, and arbitrarily limiting the ability of a network customer to schedule the output of network resources between and among control areas by limiting the output of those resources to network load in a single control area, effectively prevents the network customer from operating an integrated system.[154]

Thus, it requests that the Commission ''rule that TDU systems with loads and resources in multiple control areas may

[144] *Id.* (emphasis in original).

[145] TAPS at 28.

[146] *Id.* at 29.

[147] *Id.* at 30.

[148] *Id.*

[149] *Id.*

[150] *Id.* at 34.

[151] FERC Stats. & Regs. ¶ 31,048 at 30,325.

[152] *See* Appendix B and note 1 *supra*.

[153] TDU Systems at 15.

[154] *Id.*

designate as Network Resources for each control area the totality of their resources that meet the owned, purchased, or leased requirement of section 1.25 of the tariff.'' [155]

TDU Systems further asserts that a network customer can integrate loads and resources in multiple control areas only by purchasing network service in each control area and point-to-point service for transmission between the control areas. Thus, it argues,

> [A]bsent a regional network tariff, the Commission should require the provision of service to network customers with loads and resources 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.[156]

Commission Conclusion. We disagree with TDU Systems that network service under the pro forma tariff does not provide network customers with comparable service. Significantly, a network customer with resources and loads in multiple control areas is simply not similarly situated to a transmission provider serving native load located entirely within the transmission provider's single control area. Unlike a transmission provider serving load entirely within a single control area, a network customer with resources and loads in multiple control areas must not only integrate its resources and loads within the individual control areas, but must also arrange transmission services (network or point-to-point) for transactions occurring between and among the multiple control areas in which it seeks to transact business. However, we emphasize that if a transmission provider has resources and loads in multiple control areas, it must treat network customers that also have resources and loads in multiple control areas on a comparable basis.

In this regard, we also disagree with TDU Systems' assertion that we have required a network customer to assign a designated network resource to a single control area and limit the scheduling of such resources to serve load in a single control area. Tariff sections 30.6 and 31.3 allow for the designation of both network resources and network loads that are not physically interconnected with the transmission provider. Under the pro forma tariff, a network customer that seeks network service for all of its loads in multiple control areas may designate all such loads as network loads.[157] By designating all of its loads as network loads, such network customer will receive comparable service *in* each control area and will have the ability to schedule the output of network resources between and among control areas, just as a transmission provider or other network customer would need to do to serve load in an adjacent control area.

TDU Systems is concerned with the rates it must pay to the various control area operators to integrate its resources and loads. In rejecting TDU Systems' virtually identical argument in Order No. 888–A, we explained:

> 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.[158]

h. Network customer designation of load. TDU Systems asks the Commission to clarify that open access transmission providers must credit or eliminate double charges arising from the inability of network customers to designate less than all of the load at a delivery point as network load. TDU Systems asks the Commission to make the following points clear:

> first, there will be no double recovery of either transmission costs *or* ancillary costs that are being recovered in the existing bundled generation supply agreement; second, as the Commission properly noted in requiring the unbundling of bilateral economy energy coordination transactions, the transmission provider will not be permitted to recover more under the new arrangement for those (transmission and ancillary) services than it does under the existing bundled generation supply agreement; and third, the transmission provider is required to achieve these results by using one of the alternatives stated in Order No. 888–A at the transmission customer's election or by an alternative arrangement agreed upon by the customer.[159]

It concludes that ''[i]f the Commission relegates the customer to a section 206 complaint proceeding, it has reversed the burden of proof on the transmission provider to show that its increased rate is just and reasonable.''

Commission Conclusion. As noted by TDU Systems, we stated in Order No. 888–A that

> 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.[160]

We intended this language to apply broadly and, accordingly, clarify that it applies to transmission costs *and* ancillary costs. Moreover, while we expect transmission providers to design rates that will avoid double recovery of such transmission costs or ancillary costs, we believe that this is a fact-specific issue that is appropriately addressed on a case-by-case basis.[161] Finally, while we indicated in Order No. 888–A that a transmission customer may file a complaint under section 206 with the Commission to address any claims of double recovery, the transmission customer would most likely raise this issue in the section 205 proceeding in which the transmission provider files to initiate the particular service with the transmission customer. Indeed, it would be in such a section 205 proceeding in which this transitional problem would first arise and the transmission customer would first have the opportunity to challenge any possible double recovery.

11. Waivers of Order Nos. 888 and 889

NRECA states that the Commission's policy on waivers of Order Nos. 888 and 889 provides that such waivers terminate upon a request for service or a complaint. It argues that permitting the termination of a waiver upon a complaint improperly subjects the utility to baseless complaints and significantly diminishes the value of the waiver. It asserts that a waiver of Order No. 889 should terminate only upon a finding by the Commission that there is a valid basis for the complaint.[162] Similarly, it asserts that a waiver of Order No. 888 should terminate ''only upon a Commission order finding that, in light of changed circumstances or new evidence, the waiver should not be

[155] *Id.* at 18.

[156] TAPS at 18 n.36.

[157] Alternatively, a network customer with resources and load in multiple control areas may elect to designate only such load that is located in a single control area as its designated network load and separately arrange for transmission service (*e.g.*, point-to-point service) to serve load in adjacent control areas from generation resources located in the control area in which it designated its network load. Here too the network customer would be receiving comparable transmission service because a transmission provider or any other network customer seeking to serve load in an adjacent control area would also have to arrange for point-to-point transmission service to make the service possible.

[158] FERC Stats. & Regs. ¶ 31,048 at 30,255.

[159] TDU Systems at 23.

[160] FERC Stats. 7 Regs. ¶ 31,048 at 30,261–62.

[161] In this regard, we will not mandate that a transmission provider accept a customer-specified approach to resolving any double recovery concerns.

[162] *See also* TDU Systems at 10–12 (raising similar arguments with respect to waivers of Order No. 889).

continued and the utility should be required to file the pro forma tariff.'' [163]

Commission Conclusion. NRECA's request for rehearing with respect to the termination of a waiver of Order No. 888 should have been raised on rehearing of Order No. 888, which first established that a waiver would be granted if, among other things, the utility ''commits to file an open access tariff within 60 days of a request to use its facilities and to comply with the rule in all other ways.'' [164] Nothing set forth in Order No. 888–A changed this requirement. Accordingly, NRECA's request for rehearing was not timely filed.

However, we note that the Commission, in a recent order modifying the circumstances under which a waiver of Order No. 889 [165] will be revoked,[166] addressed this very issue:

> we will not, however, alter our determination that a utility that has been granted waiver of Order No. 888 is required to file a pro forma tariff within 60 days after it receives a request for transmission service and must comply with any additional requirements that are effective on the date of the request. The filing with the Commission of a pro forma tariff places significantly less burden on a utility than does full compliance with Order No. 889, and we continue to believe that 60 days from receipt of a request for service provides sufficient time for such compliance.[167]

12. Financial Independence of ISO Employees

NEPOOL expresses concern that the requirement in Order No. 888–A that ISO employees sever *all* financial ties ''can be interpreted to foreclose the Commission from even considering the merits of provisions for ownership of securities by ISO employees contained in NEPOOL's ISO proposal that is now pending before the Commission in Docket Nos. OA97–237–000 and ER97–1079–000.'' [168] It contends that severance of all financial ties would impose an economic hardship on certain NEPOOL employees in pension and stock ownership plans of market participants through the years. In particular, it notes that many of the existing NEPOOL staff have accumulated Northeast Utilities stock in their pension or other employee benefit plans, but that the market price of that stock has recently declined significantly. However, NEPOOL has required ISO employees to divest themselves of such securities in excess of $50,000 within six months of their employment by the ISO. Thus, NEPOOL requests that the Commission clarify that it could waive the requirement that ISO employees sever *all* financial ties with market participants in compelling circumstances or clarify the acceptable length of a transition period during which they may continue to hold such securities.

Commission Conclusion. In a recent order conditionally authorizing the establishment of an ISO by NEPOOL, the Commission specifically addressed the concerns raised here by NEPOOL.[169] The Commission rejected NEPOOL's proposal to allow employees to possess securities of market participants as long as the value does not exceed $50,000. The Commission reaffirmed its strong commitment, set forth in Order Nos. 888 and 888–A, to ensure that an ISO is truly independent and that employees of an ISO are financially independent of market participants. However, the Commission recognized, as it had in Order No. 888–A, that there may be a need for flexibility with respect to the length of a transition period and that this matter is best addressed on a case-by-case basis.

13. Distribution Charges

NY Com seeks clarification of the Commission's statement that a utility is free to include a ''distribution charge'' in a customer's service agreement and/or the network customer's network operating agreement.[170] In particular, it requests that the Commission clarify that it did not intend to preempt state jurisdiction, but rather that when a term, condition or rate is required for local distribution service, the state determination will apply. It asserts that such a clarification would avoid forum shopping that would otherwise occur. In the alternative, it requests rehearing, arguing that the Federal Power Act, its legislative history and case law all dictate against Commission jurisdiction over local distribution.

Commission Conclusion. We clarify, as requested by NY Com, that when a term, condition or rate is required for *local* distribution service the state determination applies. We reiterate that we believe there is always a local distribution service element of a retail transaction, through which the state may impose charges on the retail customer. We also reiterate, however, that where a public utility is delivering unbundled energy to a supplier that then resells the energy to an end-user, the Commission has exclusive jurisdiction over the public utility's facilities used to effect the transaction without regard to their being labeled ''transmission,'' ''distribution,'' or ''local distribution.'' [171] Moreover, where a public utility is delivering unbundled energy from a third-party supplier directly to an end user, the particular facts of the case will determine which of the facilities are FERC-jurisdictional transmission facilities and which are state-jurisdictional local distribution facilities.[172]

14. Tight Power Pools

a. Non-pancaked rates. NY Com seeks clarification of the following statement in Order No. 888–A:

> 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.[173]

It argues that this statement conflicts with other statements that ''require power pools to file joint pool-wide tariffs and to offer all transmission services that they are *capable* of providing.'' [174] NY Com asks that the Commission clarify that utility members of tight power pools must provide transmission service jointly under a single tariff. It states that this is the best way to eliminate undue discrimination. It argues that tight power pools must provide, pursuant to prior Commission orders, all transmission services that they are reasonably capable of providing and must file joint tariffs to provide

[163] NRECA at 12.

[164] FERC Stats. & Regs. ¶ 31,036 at 31,853.

[165] Open Access Same-Time Information System and Standards of Conduct, *Final Rule,* Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g,* Order No. 889–A, 62 FR 12484 (March 14, 1997), FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g,* Order No. 889–B, published elsewhere in this issue of the **Federal Register,** FERC Stats. & Regs. ¶ ________ (1997).

[166] NRECA's request with respect to the revocation of waivers of Order No. 889 is addressed in Order No. 889–B, which is being issued concurrently with this Order. In Order No. 889–B, the Commission notes that in Central Minnesota Municipal Power Agency, *et al.,* 79 FERC ¶ 61,260 (1997) (*Central Minnesota*), it already has revised its approach concerning the revocation of waivers of Order No. 889 to provide that such waivers will remain effective until the Commission takes action in response to a complaint, rather than until 60 days after a complaint to the Commission.

[167] *Central Minnesota,* 79 FERC at 62,127 (1997).

[168] NEPOOL at 2.

[169] New England Power Pool, 79 FERC ¶ 61,374 (1997), *reh'g pending.*

[170] NY Com at 5–12.

[171] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,969 (Appendix G) and Allegheny Power System, Inc., *et al.,* 80 FERC ¶ 61,143 at 61,551–52 (1997).

[172] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,969.

[173] NY Com at 12.

[174] *Id.* at 13 (emphasis in original).

transmission service on a pool-wide basis.

Commission Conclusion. NY Com appears to be confusing *services* that a power pool is capable of providing with *pricing methodologies* that a power pool may elect to use. While the Commission required that by December 31, 1996 all pool transactions be taken under a joint pool-wide tariff on file with the Commission, the Commission did not mandate a specific transmission rate structure for such tariff.[175] As we stated in Order No. 888–A, the primary goal for pooling arrangements is to ensure comparability regarding transmission services offered on a pool-wide basis. Thus, comparability is achieved if the same service is provided at the same or comparable rate to both pool and non-pool members.[176]

b. Coordination transactions. Otter Tail requests that the Commission clarify the following statement in Order No. 888–A:

> 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.[177]

It asks the Commission to clarify that this statement

> Is meant only to indicate that in the case of *different* services, one service (e.g., wholesale transactions) can be offered to all potential customers under the pool tariff, but another service (e.g., ancillary services) may not be offered to any customers under the pool tariff. Otter Tail specifically requests that the Commission clarify that where the *same* service is involved, pools cannot discriminate against certain transactions based solely on the transaction's duration, that is, pool-wide tariffs cannot exclude longer term transactions but include short-term transactions.[178]

In its case, Otter Tail is concerned that MAPP limits coordination transactions under the pool to those with a duration of two years or less and thereby prevents any longer term service from using the pool tariff. It argues that MAPP's tariff does not comply with Order No. 888 because it does not offer pool-wide service for *all* coordination transactions, regardless of duration. Otter Tail further argues that excluding the benefits of pool-wide service for coordination transactions based only on the length of term is contrary to, and incompatible with, Congress' and the Commission's goal to promote competition at the generation level and permits pools to exercise market power.

Commission Conclusion. We disagree with Otter Tail. As we stated in Order No. 888–A, the primary goal of Order No. 888's requirements for pooling arrangements, including ''loose'' pools, such as MAPP, is to ensure comparability regarding transmission services that are offered on a pool-wide basis.[179] In the case of the MAPP agreement, pool transactions are limited to periods not to exceed two years for *all* members.[180] Comparability is achieved if all parties, both pool members and non-pool members, are treated in a non-discriminatory fashion as to access to transmission services, the types of transmission services and the rates paid for such transmission services.

In addition, Order No. 888 requires loose pools to take service under a joint pool-wide tariff for all pool transactions.[181] If transactions of more than two years in duration are not pool transactions, then transmission for those transactions need not be pursuant to the pool-wide tariff, and instead would be provided pursuant to the individual companies' pro forma tariffs. This is consistent with our finding in Order No. 888–A that we will not require pool members to offer transmission services to third parties that the pool members do not provide to themselves on a poolwide basis.[182]

15. Legal Authority

Puget states that the Commission does not have the legal authority to require public utilities to file open access tariffs and argues that Order No. 888 does not contain any specific finding that any rate, term or condition of Puget's tariff is unjust, unreasonable or unduly discriminatory or preferential.

Commission Conclusion. The Commission set forth its legal authority to require public utilities to file open access tariffs in Order No. 888. Puget's request for rehearing with respect to this issue should have been raised on rehearing of Order No. 888 and therefore was not timely filed.[183]

16. Ancillary Services

Puget argues that ancillary services such as reactive power and voltage control cannot be considered merely ancillary to the provision of transmission service, but are significant generation services that should be subject to market rates. Puget asserts that ''[i]t is wholly inappropriate for the Commission to provide for the sale of power as an ancillary service under the pro forma tariff; instead, utilities such as [Puget] should be compensated for the sale of such power at market based rates.'' [184] It argues that the Commission ''must recognize that ancillary services are generation related and should be priced at market in order to be consistent.'' [185]

Commission Conclusion. Puget raises issues that were previously addressed in Order No. 888. In that order the Commission determined that ancillary services are transmission related and indicated that market-based pricing for ancillary services would be addressed on a case-by-case basis. Puget's request for rehearing with respect to these issues should have been raised on rehearing of Order No. 888 and therefore was not timely filed.

17. Fair Market Value

Puget argues that Order No. 888–A improperly shuts the door on the pricing of transmission property at fair market value. Citing footnote 261 of Order No. 888–A,[186] Puget asserts that the Commission changed its policy from Order No. 888 and claims that in Order No. 888–A ''the Commission ruled that each utility is now expressly limited by the transmission pricing policy to charging only embedded costs for existing transmission facilities to competitors and others even though rates for generation assets are priced at market.'' [187] Puget argues that Order No. 888–A achieves ''the effect of a condemnation by forcing [Puget] and other integrated electric utilities to allow competitors to use private utility property, but at less than fair market value.'' [188] Puget further argues that the Constitution ''does not permit the taking of private property of one citizen to

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[175] However, as explained in Order No. 888–A, the Commission did require that all transmission rate proposals filed in compliance with Order Nos. 888 and 888–A be cost based and meet the standard for conforming proposals set out in the Commission's Transmission Pricing Policy Statement. *See* 18 CFR 2.22.

[176] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 31,728.

[177] Otter Tail at 3 (emphasis added by Otter Tail).

[178] *Id.* at 4 (emphasis in original).

[179] FERC Stats, & Regs. ¶ 31,048 at 31,241.

[180] Mid-Continent Area Power Pool Rate Schedule, FERC No. 5.

[181] FERC Stats. & Regs. ¶ 31,036 at 31,728.

[182] *See* FERC Stats. & Regs. ¶ 31,048 at 30,241.

[183] We note that Puget filed a rehearing request of Order No. 888, but did not challenge the Commission's authority to require public utilities to file open accesss tariffs.

[184] Puget at 18.

[185] *Id.* at 19.

[186] Footnote 261, which is in the section entitled Opportunity Cost Pricing, provides in relevant part that ''[u]nder the Commission's transmission pricing policy, utilities are limited to charging the higher of embedded costs or opportunity/incremental costs.''

[187] Puget at 21.

[188] *Id.* at 21–22.

benefit competitors or other private citizens.'' It contends that

[T]he voluntary provision of transmission service to noncompetitors in an entirely cost-based integrated system is not the same as a forced provision of service and use of property by a competitor under a new set of regulations treating generation at market rates.[189]

Puget goes on to argue that

Order 888 erroneously asserts that 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.'' 62 Fed. Reg. at 12,433. For example, by illegally requiring unbundling of generation assets at market without at the same time providing for utility recovery of the fair market value of its transmission property, the Commission is attempting to deprive public utilities of fair market value compensation.[190]

In conclusion, Puget declares that ''[t]he Commission cannot create a situation in which generation is sold at a new market-based rate and transmission is limited to an old historic embedded-cost rate. Neither the Constitution nor the FPA will permit such a result.'' [191]

Commission Conclusion. We reject Puget's rehearing request. Puget makes a far-ranging argument that Order No. 888–A improperly shuts the door on the pricing of transmission property at fair market value. It bases its argument entirely on a single footnote in Order No. 888–A that has been taken completely out of context. The footnote in Order No. 888–A cited by Puget merely recites the Commission's longstanding policy as to opportunity cost pricing.[192] Indeed, in the sentence to which that footnote is attached, the Commission explicitly stated that it ''does not believe that any changes are necessary to its policy on opportunity cost recovery.'' [193] Moreover, the entire discussion to which that footnote applies is in a section entitled ''Opportunity Cost Pricing.'' [194]

18. Pre-Existing Transmission-Only Contracts

Soyland argues that the Commission's *Mobile-Sierra* findings must apply not only to wholesale requirements contracts but also to unbundled transmission-only contracts. It asserts that ''[t]here is no legitimate reason to deny unbundled, transmission-only customers timely and meaningful access to the open access regime and competitive markets on the same terms as requirements customers.'' [195] It contends that it faced the same problem as requirements customers—''use of transmission monopoly power to force a purchase of power as a condition to getting transmission access to deliver owned resources from off-system.'' [196]

Moreover, it asserts that the Commission has not explained how or why requirements contracts and transmission-only contracts should be treated differently as a result of the past and continuing changes in the industry. Soyland further states that utilities had the upper hand over ''customers who executed unbundled transmission and power supply contracts simultaneously; together, such contracts are the functional equivalent of bundled partial requirements contracts, and should not be subject to a different standard for contract reform.'' [197]

Commission Conclusion. Soyland's rehearing request addresses an issue that should have been raised on rehearing of Order No. 888. In that order, the Commission explicitly indicated that customers under *requirements* contracts executed on or before July 11, 1994 that contained *Mobile-Sierra* clauses should have the opportunity to demonstrate that their contracts no longer are just and reasonable.[198] Soyland's opportunity to request that we expand the scope of the contracts covered to include unbundled transmission-only contracts was on rehearing of Order No. 888.[199] Accordingly, Soyland's request for rehearing with respect to this issue was not timely filed.

19. Apportionment of Transmission Revenues for Public Utility Holding Companies and Power Pools

TDU Systems asks the Commission to clarify that the ''apportionment of credits for customer transmission facilities among the operating companies of a utility holding company or in power pools should be subject to Commission approval.'' TDU Systems states that the method of crediting transmission customers for operating companies' uses of their own and each other's transmission facilities in setting transmission rates must meet the Commission's comparability standards and should not be filed on a unilateral basis. Similarly, it requests that customer credits for pool participants' use of their own and each other's transmission facilities should be subject to Commission review in approving the pool's transmission rates and tariff terms and conditions.[200]

Commission Conclusion. TDU Systems' rehearing request addresses issues that should have been raised on rehearing of Order No. 888. In Order No. 888, the Commission stated that credits for customer-owned facilities should be addressed on a case-by-case basis.[201] Accordingly, TDU Systems' request for rehearing with respect to these issues was not timely filed.

20. Accounting for Transmission Provider's Own Use of Its System

TDU Systems argues that the Commission's requirement that a transmission provider's methodology to credit customers for the transmission provider's off-system sales be addressed in compliance filings and will depend on the rate design is insufficient.[202] It argues that this ignores that

Comparability has a time dimension, requiring the prompt crediting of such charges if they are not automatically accounted for in the rate design. Thus, the order fails to address whether a new kind of rate mechanism is needed if comparability is to be ensured on an ongoing basis under open-access transmission, just as the Commission years ago approved the use of fuel-adjustment clauses to deal with more volatile fuel prices. Requiring parties to resolve this issue in individual compliance filings does not address this generic problem. The Commission should provide more guidance to public utilities as to what crediting mechanisms are necessary if comparability is to be achieved.[203]

Commission Conclusion. In Order No. 888–A, the Commission explained that an automatic pass-through mechanism for revenue credits raises a number of potential problems including: ''(1) use of estimates versus actuals; (2) the appropriate time period to be utilized and (3) firm versus non-firm distinctions.'' [204] The Commission further noted that the appropriate treatment of revenue credits for off-system sales is dependent on the rate design used by a transmission provider and concluded that this issue is not appropriately resolved on a generic basis. Despite these identified problems, TDU Systems continues to request that

[189] *Id.* at 26.

[190] *Id.*

[191] *Id.* at 27.

[192] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,739–40; Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,263–66.

[193] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,625.

[194] *Id.* at 30,263.

[195] Soyland at 8.

[196] *Id.*

[197] *Id.* at 10.

[198] FERC Stats. & Regs. ¶31,036 at 31,664.

[199] In this regard, we note that other entities did file rehearing requests of Order No. 888 seeking to expand the scope of the contracts covered by the Commission's *Mobile-Sierra* findings. *See* Order No. 888–A, FERC Stats. & Regs. ¶31,048 at 30,190–91.

[200] TDU Systems at 33–34.

[201] *See* FERC Stats. & Regs. ¶31,036 at 31,742.

[202] TDU Systems at 34–35.

[203] *Id.* at 34–35.

[204] FERC Stats. & Regs. ¶31,048 at 30,310.

the Commission adopt an automatic revenue credit mechanism without attempting to address such problems or proposing an appropriate mechanism to accomplish its request.

To bolster its proposal, TDU Systems claims that automatic treatment of revenue credits is comparable to the Commission treatment of fuel charges through the use of an automatic fuel adjustment charge. We disagree. An automatic fuel cost adjustment clause was determined to be appropriate because of the unpredictability of fuel prices.[205] TDU Systems has not demonstrated that revenue credits warrant the same treatment.[206]

Moreover, TDU Systems has not demonstrated that the lack of an automatic credit mechanism is likely to result in unjust and unreasonable rates. For example, the Commission's traditional means of accounting for transmission revenues from non-firm uses of the transmission system is to reflect a representative level of revenue credits (based on historical and/or projected revenue levels) in each rate case, which has the effect of lowering the transmission rate for all firm transmission users.[207] TDU Systems has not shown why a similar rate case approach to revenue credits (as opposed to an automatic credit mechanism) is not appropriate, particularly for all transmission providers. In any event, we would anticipate little or no difference between the results of an automatic revenue credit mechanism and our traditional approach and TDU Systems has not shown otherwise.

Finally, TDU Systems' proposal is one-sided in that it would only require the automatic passthrough of revenues from the *transmission provider's* use of the transmission system for off-system sales. As the Commission stated in Order No. 888–A,

> 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.[208]

[205] *See* Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities, FERC Stats. & Regs. ¶30,524 at 30,800 (1983).

[206] In Pennsylvania-New Jersey-Maryland Interconnection, *et al.*, 81 FERC ¶_______ (1997), issued concurrently with this order on rehearing, the Commission made an exception to its general approach to revenue credits and allowed monthly crediting of non-firm transmission revenues. However, this was done in the context of a major restructuring of a tight power pool.

[207] *See, e.g.*, Pennsylvania Power Company, 26 FERC ¶61,354 at 61,781 (1984).

[208] FERC Stats. & Regs. ¶31,048 at 30,310 (emphasis added).

B. Stranded Cost Issues[209]

1. Municipal Annexation

In Order No. 888, the Commission decided that it would 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.[210] In Order No. 888–A, the Commission reconsidered this decision and concluded that it would be the primary forum for stranded cost recovery in a discrete set of municipal annexation cases, namely, those involving existing municipal utilities that annex retail customer service territories and, through the availability of Commission-required transmission access, use the transmission system of the annexed customers' former supplier to access new suppliers to serve the annexed load.[211]

A number of petitioners seek rehearing or reconsideration[212] of the Commission's decision in Order No. 888–A to be the primary forum for stranded cost recovery in the case of municipal annexations.[213] Some oppose this decision for the same reasons that they opposed the Commission's decision to be the primary forum for stranded cost recovery in the case of new municipal utilities. For example, some entities argue that the Commission does not have any authority with respect to costs in retail rate base that may be stranded as a result of the annexation of electric service territory by a municipal utility.[214] A number of petitioners also contend that municipal annexation occurs pursuant to state or local law, not federal law, and that every facet of municipal annexation, including compensation and valuation, is governed by state or local authorities.[215]

Several submit that annexation is a form of franchise competition that predated Order No. 888, that transmission access was available (though not as readily as after Order No. 888) for many franchise competitors utilizing annexation,[216] and that annexations have occurred and will continue to occur based upon motivations removed from the open access regime.[217] CAMU states that

> [a]nnexations have occurred and will continue to occur in a[n] unbroken string based upon motivations entirely removed from this Commission's open access regime. There is simply no reason to assume that the open access rule will accelerate the pace of annexations. [[218]]

NARUC asks the Commission to grant rehearing as a matter of policy. It argues that the Commission's assertion of authority to address stranded cost issues related to annexation will force the Commission to inject itself into state-established processes to second-guess a state commission's cost recovery determinations. According to NARUC, this will require the Commission to resolve difficult factual issues to match specific generation and transmission facilities with specific annexed customers.[219]

CAMU similarly contends that the Commission's assertion that it is the primary forum for the resolution of annexation-related stranded cost issues will introduce needless procedural complications. CAMU submits that various state-created mechanisms exist for the identification and payment of just compensation in the case of municipal annexations. It questions

[209] Some of the rehearing requests raise issues that previously were raised on rehearing of Order No. 888 and were addressed by the Commission in Order No. 888–A. The Commission will not further address such issues in this proceeding. For example, Puget repeats some of the same arguments that it raised in its request for rehearing of Order No. 888 concerning the federal causes of stranded costs, the Commission's alleged abdication of its legal authority to ensure recovery of stranded costs associated with bypass and retail wheeling, the application of the reasonable expectation test to departing retail customers, and the Commission's failure to include deferred costs in the revenues lost formula. The Commission addressed these concerns in Order No. 888–A. *See* FERC Stats. & Regs. ¶31,048 at 30,358–62, 30,424, 30,426–27. TDU Systems reiterates its objection to the Commission's elimination of the section 35.15 prior notice of termination requirement for power sales contracts executed after July 9, 1996 that terminate by their own terms. The Commission addressed TDU Systems' concerns in this regard in Order No. 888–A. *See* FERC Stats. & Regs. ¶31,048 at 30,392, 30,393–94.

[210] FERC Stats. & Regs. ¶31,036 at 31,818.

[211] FERC Stats. & Regs. ¶31,048 at 30,408–09.

[212] As discussed above, APPA filed its request for rehearing out-of-time. Accordingly, we are treating APPA's pleading as a motion for reconsideration.

[213] *See* APPA, CAMU, IL Com, NARUC, TAPS. TDU Systems, on the other hand, argues that the Commission should permit non-public utilities providing reciprocal transmission service to recover stranded costs arising from municipal annexation. TDU Systems submits that allowing public utilities to seek stranded cost recovery arising from municipal annexation exacerbates the unequal and unduly discriminatory treatment accorded transmission dependent utilities and electric cooperatives.

[214] *See* APPA at 11–12; IL Com at 4–5; NARUC at 2–3.

[215] *E.g.*, APPA at 12–13; NARUC at 3; TAPS at 24–25. APPA objects that federal regulation of stranded costs associated with municipal annexation results in the establishment of overlapping federal/state authority that precludes the execution of state laws by state authority in a matter normally within the power of the state, in violation of the Tenth Amendment. APPA at 13.

[216] APPA at 11; *see also* NARUC at 3.

[217] CAMU at 2.

[218] *Id.*

[219] NARUC at 3–4.

how the Commission will offset against stranded cost recovery any compensation provided under state law and whether the Commission will await the completion of state proceedings before it addresses the issue.[220] CAMU asks the Commission to defer to existing state mechanisms and to be the primary forum for the resolution of stranded cost recovery issues in annexation situations only where there is no state procedure for stranded cost recovery.

IL Com argues that determining whether the availability of wholesale open access is the principal cause of the stranding of public utility costs would be administratively difficult.[221] IL Com also submits that the Commission's expectation that parties raise retail-turned-wholesale stranded cost claims before this Commission in the first instance is internally inconsistent with, and contradictory to, its statements that it will give great weight in its proceedings to a state's view of what might be recoverable and will deduct any recovery a state has permitted from departing retail-turned-wholesale customers from the costs for which the utility will be allowed to seek recovery under the Rule.[222]

Commission Conclusion. After careful consideration of the arguments raised on rehearing, we have decided not to grant rehearing, but we do provide further clarification of our decision in Order No. 888–A to be the primary forum for stranded cost recovery in certain cases involving municipal annexation. As a policy matter, we will consider recovery of stranded costs that potentially could arise as a result of municipal annexation but only when there is a sufficient nexus in such cases to the Commission's Open Access Rule. To clarify, this determination to be the primary forum is not a blanket determination for all cases involving annexation. A determination of what circumstances make Commission review appropriate will be made on the facts pertinent to individual cases. The Commission has limited the opportunity to seek stranded cost recovery under the Rule to situations in which the availability and use of wholesale open access transmission enable a generation customer to escape a current power supplier to obtain cheaper power supplies. Annexations occur for a myriad of reasons that may have nothing to do with seeking less expensive power supplies (for example, tax or zoning considerations or consolidation of local public services). These reasons existed before adoption of Order No. 888 and, absent the nexus to the new availability of these transmission services, would not require us to consider the stranded costs from annexation in the first instance. On the other hand, an existing municipal utility that has newly-annexed territory may use an open access tariff of the annexed customers' former power supplier. Accordingly, the Commission does not believe it is necessary to reverse its previous position that annexations may raise jurisdictional stranded cost issues but instead provides this clarification.

In the course of reviewing the rehearing petitions on annexation, the Commission has also had the opportunity to reflect on the rationale for our decision to be the primary forum for addressing the recovery of stranded costs associated with retail-turned-wholesale customers (including a newly-formed municipal utility). We wish to further elaborate upon and clarify our prior discussions about recovery of costs stranded by retail-turned-wholesale customers.[223]

First, in setting forth our position on costs stranded in certain retail-turned-wholesale and municipal annexation situations, the Commission recognized that states may also have jurisdiction over retail-turned-wholesale stranded costs and that state adjudications of such costs may precede consideration of them here.[224] Moreover, we indicated that ''we are not second-guessing the states as to what a utility may recover under state law.''[225] As we stated in Order No. 888–A and reiterate here,

> 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.[226]

In making this statement, the Commission clearly recognized that it may indeed be the states that first address the difficult stranded cost issues associated with the formation of new municipal utilities or other wholesale entities. The Commission contemplated then, as now, that it would nevertheless adjudicate these stranded cost issues where states lack authority to do so or where, based on the record before us, they fail to provide a forum.[227]

Second, as the Commission stated in Order No. 888–A,

> if the state has permitted any recovery from departing retail-turned-wholesale customers [for example, if it imposed an exit fee prior to, or as a condition of, creating the wholesale entity], 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.[228]

Further, we will take into account state findings on cost determinations associated with retail-turned-wholesale situations and ''we will give great weight in our proceedings to a state's view of what might be recoverable.''[229] We believe it is important to emphasize that in those instances where states do address stranded costs associated with retail-turned-wholesale customers and in cases of municipal annexation, we intend to give substantial deference to their determinations.

2. Pre-existing Transmission Rights

TAPS requests clarification that the required nexus between the availability and use of Commission-required transmission access and the stranding of costs would not be met ''if the municipal utility, including as expanded through annexation, possessed rights to transmission prior to Order No. 888 and EPAct (for example, NRC license conditions and the like).''[230] TAPS submits that ''[t]he utility exercising these transmission rights should not be subject to stranded costs claims before the Commission simply because the municipal utility chooses to use the Commission's preferred open access tariff, instead of a

[220] CAMU at 3–5. CAMU notes that some state compensation statutes require the annexing municipality to pay ''expectation'' damages for a defined future period based upon revenues received from the annexed area. CAMU says that this element of damage, which is applied in addition to payment for condemned facilities, is meant to liquidate claims for lost service territory, idled generation assets and other business opportunities, but the awards do not separately value each of these elements of damage. CAMU questions how the Commission is going to ascertain what element of recovery pertains specifically to stranded costs if a state has adopted this liquidated damages approach. *Id.* at 5.

[221] IL Com at 5.

[222] *Id.* at 5–6.

[223] In so doing, we also reiterate our concern (expressed in Order Nos. 888 and 888–A) 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. In Order Nos. 888 and 888–A, we reserved the right to address such situations on a case-by-case basis. Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,819; Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,409.

[224] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,819; Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,405.

[225] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,405.

[226] *Id.* at 30,410.

[227] *See* City of Las Cruces, New Mexico, 80 FERC ¶ 61,160 (1997).

[228] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,405. *See also* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,819.

[229] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,405.

[230] TAPS at 27.

bilateral or other arrangement available under pre-existing rights.'' [231]

Commission Conclusion. We will deny TAPS' requested clarification. The existence of rights to transmission prior to Order No. 888 would not, in and of itself, indicate that the customer should be relieved of potential stranded cost liability under Order Nos. 888 and 888–A.[232] It may be that a customer with some right to transmission service prior to Order No. 888 (for example, as a consequence of NRC license conditions), was unable to reach an alternative supplier through the use of that transmission. Thus, notwithstanding the existence of pre-existing transmission rights, and depending on the facts of a particular case, it may be that the utility incurred costs based on a reasonable expectation of continuing to serve the customer.

On this basis, the Commission will not conclusively presume that a customer with a pre-existing right to transmission service could never be subject to a stranded cost obligation under Order Nos. 888 and 888–A. Similarly, the Commission will not conclusively presume that the mere existence of a pre-existing right to transmission service precludes any reasonable expectation of continued service by the utility. However, the existence of pre-existing transmission rights, and any circumstances surrounding them, may be used as evidence in the determination of whether the utility had a reasonable expectation of continuing to serve a customer. [233]

3. Load Growth and Excess Capacity

Boston Edison seeks rehearing of the Commission's finding in Order No. 888-A that a ''cost is not stranded if it is fully recovered in the cost-based rates paid by native load.'' [234] It submits that this phrase

> Suggests that the cost of capacity released by a departing wholesale customer can and should be recovered in the rates of the remaining retail and wholesale customers if the remaining customers' load or load growth will be sufficient to absorb the released capacity. . . . Such cost shifting directly contradicts the cost responsibility principles set forth in Order No. 888 [*i.e.*, direct assignment].[235]

Boston Edison objects that the rationale for this policy reversal is not articulated in Order No. 888–A.

Commission Conclusion. At the outset, we reiterate that we remain committed to the cost responsibility principles established in Order No. 888 and continue to believe that a departing wholesale customer should be responsible for the costs it strands. Our statement that a ''cost is not stranded if it is fully recovered in the cost-based rates paid by native load'' was not meant to imply that the cost of capacity released by a departing wholesale customer should always be recovered in the rates of the remaining retail and wholesale customers through load growth. Rather, our discussion of load growth correctly recognizes that in some instances a utility can meet native load growth with existing capacity freed-up by the departure of wholesale load. If a utility can recover the costs of existing capacity freed up by a departing customer from another customer or group of customers, the expected revenues should be reflected in the CMVE component of the formula.[236] Moreover, our requirement that a utility reflect in the CMVE component of the formula the revenues it expects to receive from the sale of the released capacity does not automatically result in remaining customers being forced to subsidize a departing customer's stranded cost obligation as Boston Edison posits. Rather, the rate treatment of the released capacity needed to meet the load growth of native load customers is an open issue that is properly addressed in future rate proceedings.

In short, the revenues lost approach already takes account of the marketability of the released capacity and appropriately incorporates load growth associated with remaining retail and wholesale customers and does not contradict the cost responsibility principle set forth in Order Nos. 888 and 888–A.

4. G&T and Distribution Cooperatives

RUS seeks rehearing and clarification of the Commission's determination in Order No. 888–A that, unless stranded costs arise as a result of a section 211 order to a G&T cooperative, G&T cooperatives may not seek (through the Commission) recovery of stranded costs from the customers of their distribution members. RUS argues that the customers of a G&T cooperative's distribution members, as well as the distribution members themselves, meet the Commission's pro forma tariff definition of ''native load customer'' with respect to the G&T. It says that, ''as native load customers, both distribution members and their customers should be responsible to a G&T for stranded costs arising from their use of Commission-required transmission access, or from state mandated retail wheeling.'' [237]

RUS also questions the Commission's assertion that '''to treat a G&T cooperative and its member distribution systems 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 the purposes of Order No. 888's reciprocity provision.'' [238] RUS asserts that different treatment for different purposes is justified because the relevant issues with respect to the application of the reciprocity requirement on a system-wide basis and the ability to recover stranded costs on a system-wide basis are different. RUS submits that the Commission confuses corporate affiliation with economic integration, and that lack of corporate affiliation does not preclude economic integration. RUS says that although G&T cooperatives and their distribution members are operationally separate, G&T cooperatives and their distribution members function in many ways like a single economic unit. According to RUS, G&Ts undertake an obligation to construct and operate their systems to meet the reliable electric needs of their distribution members and customers of their distribution members, and G&T cooperatives and their members are bound together by long-term requirements contracts.

RUS states that, as single economic units, G&T cooperatives or distribution members both should be able to seek recovery of stranded costs from the customers of distribution members. RUS contends that ''the Commission's reliance on distribution members to seek to recover stranded costs 'through contracts with [their] customers or through the appropriate regulatory authority' is misplaced'' because ''[d]istribution members—many of which are not subject to state commission jurisdiction—may have neither an appropriate regulatory forum through which to seek stranded cost recovery, nor the ability to seek to recover stranded costs incurred by their

[231] *Id.*

[232] As we explained in Order No. 888–A, we declined to include ''exercise of pre-existing contract rights for transmission and designation of wholesale loads'' as an example of a situation for which stranded costs may not be sought because we are not prepared to make individual factual determinations in the context of the Rule. The Commission will address specific requests for stranded cost recovery on the facts presented and the merits of the particular request. FERC Stats. & Regs. ¶ 31,048 at 30,358.

[233] *See* Duquesne Light Company, 79 FERC ¶ 61,116 at 61,520 (1997).

[234] FERC Stats. & Regs. ¶31,048 at 30,440.

[235] Boston Edison at 3.

[236] *See* City of Alma, Michigan, 80 FERC ¶61,265 at 61,961 (1997).

[237] RUS at 16.

[238] *Id.* (citing Order No. 888–A, FERC Stats. & Regs. ¶31,048 at 30,366).

G&T cooperatives to serve native load customers.'' [239]

Finally, RUS argues that failing to permit G&T cooperatives to seek recovery of stranded costs arising from the loss of native load customers due to Commission-required transmission access or the lack of state commission authority to permit stranded cost recovery will result in unduly discriminatory treatment of cooperatives. Where G&T costs are stranded by the ability of customers of distribution members to switch suppliers through Commission-required transmission access, RUS submits that there is a direct nexus between Commission-required access and the stranding of costs. In the case of retail stranded costs, RUS says that many state regulatory authorities do not have the authority under state law to regulate distribution or G&T cooperatives, thereby creating a regulatory gap. RUS states that

> [f]ailure to allow a G&T the opportunity to recover stranded costs caused by [the] departure of any of its native load customers, including both distribution members and the customers of the distribution members, will drastically reduce the G&T's ability to cover its costs, including payments on RUS-financed debt, thereby endangering the existence of the G&T itself and exposing Federal taxpayers to the risk of massive loan defaults.[240]

Commission Conclusion. We will deny RUS' rehearing request. To grant the request would require the Commission to reach beyond its regulatory authority (and allow entities not subject to our sections 205 and 206 jurisdiction an opportunity to recover stranded costs) and would broaden the scope of the Order Nos. 888 and 888–A stranded cost recovery mechanism.[241] Indeed, RUS' rehearing request appears to be based on a misunderstanding of the limited scope of the stranded cost recovery mechanism contained in Order Nos. 888 and 888–A.

The stranded cost recovery provisions in Order Nos. 888 and 888–A apply, in the case of wholesale stranded costs, to public utilities [242] and transmitting utilities.[243] In the case of stranded costs associated with retail wheeling customers, the provisions of the Rule apply only to public utilities.[244] The Commission has limited the opportunity for public utilities and transmitting utilities to seek stranded cost recovery under Order Nos. 888 and 888-A primarily to two discrete situations: (1) costs associated with customers under wholesale requirements contracts executed on or before July 11, 1994 (referred to 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 (including bundled retail customers of a utility that become bundled retail customers of a new municipal utility).[245]

As the Commission explained in Order No. 888–A, 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 we have 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 or contractual channels, this Commission does not have authority to allow them to seek recovery of stranded costs unless they do so in conjunction with transmission access that they are required to provide through a section 211 order. In the latter case, 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 that did not contain an exit fee or other explicit stranded cost provision.[246]

As we also explained in Order No. 888–A, a G&T cooperative that *is* a public utility (a non-RUS financed 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 Order No. 888's stranded cost recovery provisions. We said that, 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. In Order No. 888–A, we explained why 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 the Rule. We indicated that ''[t]he 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.'' [247] We explained that commenters had provided no basis for making an exception in the case of cooperatives. Further, we said that ''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.'' [248]

[239] *Id.* at 17.

[240] *Id.* at 19.

[241] RUS expresses concern in its rehearing request that distribution members ''may have neither an appropriate regulatory forum through which to seek stranded cost recovery, nor the ability to seek to recover stranded costs incurred by their G&T cooperatives to serve native load customers.'' RUS at 17. However, presumably when a retail customer of a distribution cooperative switches suppliers, the retail customer would still have to use the distribution lines of the distribution cooperative to receive its power. RUS has not explained why the distribution cooperative cannot assess a charge to recover stranded costs when the retail customer uses those lines.

[242] A ''public utility'' is defined under section 201(e) of the FPA as ''any person who owns or operates facilities subject to the jurisdiction of the Commission under this Part (other than facilities subject to such jurisdiction solely by reason of sections 210, 211, or 212).'' 16 U.S.C. 824(e).

[243] A ''transmitting utility'' is defined under section 3(23) of the FPA as ''any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.'' 16 U.S.C. 796(23).

[244] As we explained in Order No. 888–A, our decision to entertain (in certain limited circumstances) requests to recover stranded costs associated with retail wheeling customers applies to public utilities only because it 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. FERC Stats. & Regs. ¶ 31,048 at 30,419. Since RUS-financed cooperatives are not public utilities subject to our jurisdiction under sections 205 and 206 of the FPA, we do not have authority to allow them to seek recovery under Order Nos. 888 and 888–A of stranded costs associated with retail wheeling customers.

[245] Whether a G&T cooperative's member distribution cooperatives and the customers of the distribution cooperatives meet the definition of ''native load customer'' under the open access tariff (as RUS submits they do) is not relevant for purposes of the stranded cost recovery mechanism set forth in Order Nos. 888 and 888–A.

[246] FERC Stats. & Regs. ¶31,048 at 30,366.

[247] *Id.*

[248] *Id.* We continue to believe that it would be inconsistent to treat G&T cooperatives and their member distribution cooperatives differently for purposes of the reciprocity condition and stranded

Although RUS refers in its rehearing request to a scenario in which costs may be stranded by the ability of customers of a distribution cooperative to switch suppliers through the use of Commission-required transmission access, the scenario RUS posits is not one for which Order Nos. 888 and 888–A would permit an opportunity for recovery. Because the Commission cannot order retail wheeling, the principal way in which the retail customers of a distribution cooperative could use Commission-required transmission access (and trigger stranded costs on the part of the distribution cooperative) would appear to be through municipalization (*i.e.*, through the creation of a new wholesale entity to obtain power supplies on their behalf in lieu of obtaining power from the distribution cooperative). In such a scenario, however, since the distribution cooperative (if RUS-financed) would not be a Commission-jurisdictional public utility or transmitting utility, it would not be allowed to seek stranded cost recovery under Order Nos. 888 and 888–A.

5. Treatment of Contracts Extended or Renegotiated Without a Stranded Cost Provision

In Order No. 888–A, the Commission clarified that it will consider on a case-by-case basis whether to waive the provisions of 18 CFR 35.26 (which define a ''new wholesale requirements contract'' as ''any wholesale requirements contract executed after July 11, 1994, *or extended or renegotiated to be effective after July 11, 1994*'' (emphasis added)) and 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.[249]

Port of Seattle opposes the Commission's decision in this regard. It argues that the Commission in Order No. 888–A sided with Puget on an issue that is being litigated between Port of Seattle and Puget in a separate proceeding (Docket No. ER96–714), and that the Commission improperly prejudiced Port of Seattle by not addressing the concerns expressed by Port of Seattle in the underlying case.[250] It submits that Order No. 888–A was not the forum in which it expected the final decision in Docket No. ER96–714 to be made, and that its procedural rights have been violated. Port of Seattle asks the Commission on rehearing to withdraw any determination, reference or statement in Order No. 888–A that addresses the issues pending in Docket No. ER96–714.

Port of Seattle further argues that the Commission improperly granted Puget an exclusive waiver of (or private exception to) the Rule's definition of ''new'' contracts.

Commission Conclusion. We will deny Port of Seattle's request for rehearing. Port of Seattle misconstrues the scope of the Commission's decision and its effect on the pending proceeding in Docket No. ER96–714–001. The Commission's decision in Order No. 888–A to consider on a case-by-case basis whether to waive the provisions of 18 CFR 35.26 and treat a contract extended or renegotiated to be effective after July 11, 1994, but before March 29, 1995, as an existing contract for stranded cost purposes does *not* constitute a ruling on the merits in the pending proceeding in Docket No. ER96–714–001. In Order No. 888–A, the Commission has gone no further than to state that the matter should be considered on a case-by-case basis, and to acknowledge that the issue, as between Puget and Port of Seattle, is pending in Docket No. ER96–714–001.[251] Contrary to Port of Seattle's claim, Order No. 888–A does not grant Puget a waiver of the Rule's definition of ''new wholesale requirements contract.''

6. Customer Expectations of Continued Service at Below-Market Rates

TDU Systems seeks rehearing of the Commission's decision not to adopt a generic mechanism 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. TDU Systems states that the Commission's decision rests on the conclusion that, 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. TDU Systems maintains that this finding rests on a false distinction between the rate the wholesale requirements customer reasonably could have expected to pay and the rate the wholesale requirements seller reasonably could have expected to collect. It says that neither stranded costs nor ''stranded benefits'' [252] arise from a right to, or expectation of, a grandfathered rate. TDU Systems contends that ''stranded benefits'' arise because, prior to open access transmission, wholesale requirements customers had a reasonable expectation of continuing to receive wholesale service at just and reasonable cost-based rates. It argues that when open access transmission allows the supplier to charge a higher market-based rate instead, the customer's expectation of continued cost-based service is destroyed, and the customer may lose the benefits it had under the prior regulatory regime.

TDU Systems submits that while Order No. 888-A suggests that customers could not reasonably expect to continue paying their existing rate, the revenues lost approach to quantifying stranded costs assumes that sellers reasonably expected to continue collecting a cost-based rate equal to the existing rate. TDU Systems says that the Commission's best estimate of the seller's lost revenue from a wholesale requirements contract is based on the seller's existing, cost-based, just and reasonable rate—the same existing cost-based rate that the Commission in Order No. 888–A finds the captive requirements customer had no reasonable expectation of continuing to pay. TDU Systems says these findings directly contradict one another.[253]

TDU further challenges the Commission's statement that ''it is not clear'' that the customer could show it reasonably expected continued service ''at the existing contract rate (which may be below the market price)'' because the utility might have filed changed rates during the contract term or sought new rates at the end of the contract term. TDU Systems submits that before open access, established Commission policy would only have allowed the monopoly utility to charge its captive wholesale requirements

cost recovery, notwithstanding RUS' argument to the contrary.

[249] FERC Stats. & Regs. ¶ 31,048 at 30,396.

[250] Port of Seattle at 7. Port of Seattle also contends that the Commission mischaracterized Port of Seattle's position when it referred to Puget's statement that the parties were working within the context of the stranded cost NOPR, which provided that the utility had three years from the date of the publication of the final rules to negotiate or file for stranded cost recovery. Port of Seattle says its assumption and position was that Puget made the business decision not to include a stranded cost or exit fee provision in its letter agreement, thus preventing its recovery of any stranded costs. *Id.* at 8.

[251] We note that a certification of an uncontested offer of settlement in that proceeding is pending before the Commission.

[252] TDU Systems uses the term ''stranded benefits'' to refer to the benefits to a wholesale requirements customer that may be lost if ''open access transmission forces [the customer] to buy power at market-based rates'' instead of at cost-based rates. TDU Systems at 25.

[253] *Id.* at 27–28.

customer a cost-based rate, whether that rate was above or below market price.[254]

TDU Systems asks the Commission to adopt a generic mechanism to allow customers to demonstrate and recover their stranded benefits, just as it has done for the recovery of utility stranded costs. If the Commission is unwilling to promulgate such a generic rule, TDU Systems asks that the Commission clarify the standard that a customer must meet in seeking relief under section 206. It says that although Order No. 888-A states that a customer may file a petition under section 206 ''to show that the contract should be extended at the existing contract rate,'' the issue is not whether to extend a contract at the existing rate, but whether to continue requirements service at a cost-based rate. It asks the Commission to correct its description in Order No. 888–A of the standard the customer must meet in a case-by-case proceeding and the relief the Commission would provide.

Commission Conclusion. As discussed below, we will deny TDU Systems' request for rehearing on this issue, but will grant, in part, its request for clarification.

In Order No. 888–A, the Commission rejected TDU Systems' request that the Commission provide a generic mechanism to allow existing requirements customers 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. The Commission noted that TDU Systems had requested that the customer be given 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 ''stranded benefits'' payment from the utility consisting of the difference between what the customer must pay for new supplies and what it paid under the contract.[255] We concluded that we did not have a sufficient basis on which to make generic findings or provide a generic formula for addressing this issue:

> 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.[256]

At the same time, however, we indicated that a customer under a contract may exercise its procedural rights under section 206 of the FPA to show that the contract should be extended at the existing contract rate. We noted that the customer also may make such a showing in the context of a utility's proposed termination of a contract pursuant to the § 35.15 notice of termination (approval) requirement, which the Commission has retained for power supply contracts executed prior to July 9, 1996 (the effective date of Order No. 888).

TDU Systems has not persuaded us that our decision to address this issue on a case-by-case, not a generic, basis is in error. Notwithstanding TDU Systems' arguments, we continue to believe that the extent to which a customer could demonstrate a reasonable expectation of continued service at the existing contract rate (or at a cost-based rate, if that was the customer's expectation) is best addressed on a case-by-case basis. As we explained in Order No. 888–A, we do not intend to prejudge whether a requirements customer could ever make such a showing, nor do we intend to preclude a customer from attempting to make such a showing in appropriate circumstances.

In response to TDU Systems' request that the Commission clarify the standard that a requirements customer must meet in seeking relief under section 206, we clarify that a customer may exercise its procedural rights under section 206 to show *either* that the contract should be extended at the existing contract rate or, as TDU Systems suggests, that the contract should be extended at a cost-based rate. However, the relief that the Commission would provide in such a case is a matter that is more appropriately determined on a case-by-case basis based on the particular facts and circumstances.

7. Miscellaneous

IL Com seeks rehearing of the following sentence in Order No. 888–A: ''It was not 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 needs.'' [257] IL Com objects that this sentence prejudges the reasonable expectation issue.[258] It asks that the Commission withdraw the quoted sentence in full or, at a minimum, withdraw the reference to retail customers in the quoted sentence.

IL Com also seeks clarification of the Commission's statement in Order No. 888–A that ''[i]f 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.'' [259] IL Com asks the Commission to withdraw the words ''or a former retail customer'' from this sentence and to clarify that it is not prejudging utilities' entitlement to retail stranded cost recovery and is not imposing a ''legitimate, prudent and verifiable'' standard for the recovery of retail stranded costs.[260]

Commission Conclusion. The Commission statements that are the subject of IL Com's request for rehearing initially appeared in Order No. 888 [261] and were repeated in Order No. 888–A's summarization of Order No. 888. IL Com's request for rehearing with respect to these statements should have been raised on rehearing of Order No. 888 and therefore was not timely filed. However, we clarify that while we will not withdraw our statements, the statements are not intended to prejudge the reasonable expectation issue as it might apply to any state proceedings on retail stranded costs.

V. Environmental Statement

In Order No. 888–A, the Commission denied requests for rehearing on eight categories of issues relating to the Commission's analysis of environmental issues. No rehearing requests were filed concerning Order No. 888–A's analysis of environmental issues.

VI. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act [262] 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 Order No. 888, the Commission certified that the Open Access and Stranded Cost Final Rules would not impose a significant economic impact on a substantial number of small entities. In

[254] *Id.* at 28–29

[255] FERC Stats. & Regs. ¶31,048 at 30,391.

[256] *Id.* at 30,393 (emphasis in original),

[257] *Id.* at 30,351 (emphasis added by IL Com).

[258] IL Com at 9–10.

[259] FERC Stats. & Regs. ¶31,048 at 30,351 (emphasis added by IL Com).

[260] IL Com. at 10–11.

[261] *See* FERC Stats. & Regs. ¶31,036 at 31,789.

[262] 5 U.S.C. 601–612.

Order No. 888–A, the Commission addressed requests for rehearing that questioned this certification and that the final rule would not impose a significant economic impact on a substantial number of small entities. No rehearing requests of Order No. 888–A were filed on this issue and the Commission finds no reason to alter its previous findings on this issue.

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). [263] Given that this order on rehearing makes only minor revisions to Order Nos. 888 and 888–A, 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 Nos. 888 and 888–A. 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

The tariff change to Order Nos. 888 and 888–A made in this order on rehearing (see footnote 1) will become effective on February 9, 1998. The current requirements of Order Nos. 888 and 888–A will remain in effect until this order becomes effective.

By the Commission.

Lois D. Cashell,

Secretary.

Note: The following Appendices will not appear in the Code of Federal Regulations.

Appendix A—Order No. 888–B: List of Petitioners

1. American Public Power Association, Colorado Association of Municipal Utilities, Municipal Electric Systems of Oklahoma, and Utah Associated Municipal Power Systems (APPA) [1]
2. Bonneville Power Administration (BPA)
3. Arizona Public Service Company (Arizona)
4. Boston Edison Company, Central Vermont Public Service Corporation, Florida Power Corporation, Montaup Electric Company, and Wisconsin Public Service Corporation (Boston Edison)
5. Coalition for a Competitive Electric Market (CCEM) [2]
6. Central Maine Power Company (Central Maine)
7. Coalition for Economic Competition (Coalition for Economic Competition) [3]
8. Colorado Association of Municipal Utilities (CAMU)
9. Dairyland Power Cooperative (Dairyland)
10. Edison Electric Institute (EEI) [4]
11. Illinois Commerce Commission (IL Com)
12. Kansas City Power & Light Company (KCPL)
13. Metropolitan Edison Company (Met Ed)
14. National Association of Regulatory Utility Commissioners (NARUC)
15. National Rural Electric Cooperative Association (NRECA)
16. New England Power Pool Executive Committee (NEPOOL)
17. Public Service Commission of the State of New York (NY Com) [5]
18. Niagara Mohawk Power Corporation and PURPA Reform Group (NIMO) [6]
19. Otter Tail Power Company (Otter Tail)
20. Puget Sound Energy, Inc. (Puget) [7]
21. Rural Utilities Service, USDA (RUS)
22. Port of Seattle (Port of Seattle)
23. Soyland Power Cooperative, Inc. (Soyland)
24. Transmission Access Policy Study Group and certain of its Members (TAPS) [8]
25. Transmission Dependent Utility Systems (TDU Systems) [9]

(**Name of Transmission Provider**) **Open Access Transmission Tariff Original Sheet No.**

Revision to Pro Forma Open Access Transmission Tariff Pursuant to Order No. 888–B

Appendix B

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

[FR Doc. 97–31841 Filed 12–8–97; 8:45 am]

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[263] The OMB control number for this collection of information is 1902–0096.

[1] APPA filed its request for rehearing out-of-time on April 4, 1997. As discussed in Order No. 888–B, the Commission is accepting this pleading as a motion for reconsideration.

[2] CNG Energy Services Corp., Coastal Electric Services Company, Destec Power Services, Inc., Enron Power Marketing, Inc., Koch Energy Trading, Inc., NorAm Energy Services, Inc., and Vitol Gas & Electric Services, Inc.

[3] General Public Utilities Corp., Illinois Power Co., Long Island Lighting Co., and New York State Electric & Gas Corp.

[4] EEI filed its request for rehearing out-of-time on April 4, 1997. As discussed in Order No.888–B, the Commission is accepting this pleading as a motion for reconsideration.

[5] Independent Power Producers of New York, Inc. (NY IPPs) filed an answer on April 11, 1997.

[6] Granite State Hydropower Association filed an answer on April 21, 1997.

[7] Formerly Puget Sound Power & Light Company.

[8] American Municipal Power-Ohio, Inc., Illinois Municipal Electric Agency, Indiana Municipal Power Agency, Littleton Electric Light Department, Massachusetts Municipal Wholesale Electric Company, Michigan Public Power Agency, Municipal Energy Agency of Mississippi, Municipal Energy Agency of Nebraska, New Hampshire Electric Cooperative, Inc., Northern California Power Agency, Virginia Municipal Electric Association No. 1, on behalf of itself and its members (City of Franklin, City of Manassas, Harrisonburg Electric Commission, Town of Blackstone, Town of Culpepper, Town of Elkton, and Town of Wakefield), and Wisconsin Public Power, Inc. The operating companies of the American Electric Power System (AEP) filed an answer on April 17, 1997.

[9] Arkansas Electric Cooperative Corporation, Golden Spread Electric Cooperative, Inc., Holy Cross Electric Association, Kansas Electric Power Cooperative, Inc., Magic Valley Electric Cooperative, Inc., Mid-Tex Generation and Transmission Electric Cooperative, Inc., North Carolina Electric Membership Corporation, Oklahoma Municipal Power Authority, Old Dominion Electric Membership Corporation, and Seminole Electric Cooperative, Inc.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 37

[Docket No. RM95–9–002; Order No. 889–B]

Open Access Same-Time Information System and Standards of Conduct

Issued November 25, 1997.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final order; order denying rehearing.

SUMMARY: The Federal Energy Regulatory Commission is denying the requests for rehearing of its order on rehearing of the final rule in this proceeding. The final rule required public utilities that own, control, or operate facilities used for the transmission of electric energy in interstate commerce to create or participate in an Open Access Same-Time Information System (OASIS) in conformance with Commission regulations. The final rule also required