amounts of iron-containing supplement powders which are difficult for children to handle without spilling or to swallow without gagging. A child would have to ingest approximately 11 tablespoons of petitioner's product (20 mg/kg in a 10 kg child) in order to produce a minimally toxic dose. Approximately 100 tablespoons would be required for a lethal dose. Most of the factors that make toxic ingestions of petitioner's unflavored product unlikely would also apply to flavored supplement powders.

After considering the available information, the Commission preliminarily concludes that the degree and nature of the hazard to children presented by the availability of dietary supplement powders with no more than the equivalent of 0.12 percent weight-to-weight elemental iron are such that special packaging is not required to protect children from serious personal injury or serious illness resulting from handling, or ingesting such substance. Accordingly, the Commission voted to grant the petition and proposes to amend 16 CFR 1700.14(a)(13) to exempt from requirements for child resistant packaging those dietary supplement powders with no more than the equivalent of 0.12 percent weight to-weight-elemental iron.

E. Regulatory Flexibility Certification

Under the Regulatory Flexibility Act (Public Law 96–354, 5 U.S.C. 601 *et seq.*), when an agency issues proposed and final rules, it must examine the rules' potential impact on small businesses. The Act requires agencies to prepare and make available for public comment an initial regulatory flexibility analysis if a proposed rule would have a significant impact on a substantial number of small businesses, small organizations, and small governmental jurisdictions.

The exemption proposed below, to exempt powdered iron-containing dietary supplements from CRP requirements, will give manufacturers of these products the option of packaging products using any packaging they choose. As far as CPSC is aware, powdered iron-containing dietary supplements are not currently packaged in CRP. The Commission's Compliance staff is exercising its enforcement discretion regarding these products pending completion of this rulemaking. Thus, the proposed exemption will bring no change in the current packaging of products subject to the exemption. Accordingly, the Commission concludes that this exemption will not have any significant economic effect on a substantial number of small entities.

F. Environmental Considerations

The Commission's regulations at 16 CFR 1021.5(c)(3) state that rules exempting products from child-resistant packaging requirements under the PPPA normally have little or no potential for affecting the human environment. The Commission does not foresee any special or unusual circumstances surrounding this proposed rule. Therefore, exempting these products from the PPPA requirements will have little or no effect on the human environment. For this reason, the Commission concludes that no environmental assessment or impact statement is required in this proceeding.

G. Effective Date

Since the proposed rule provides for an exemption, no delay in the effective date is required. 5 U.S.C. 553(d)(1). Accordingly, the rule shall become effective upon publication of the final rule in the **Federal Register**.

List of Subjects in 16 CFR Part 1700

Consumer protection, Infants and children, Packaging and containers, Poison prevention, Toxic substances.

Conclusion

For the reasons given above, the Commission amends Title 16 of the Code of Federal Regulations to read as follows:

PART 1700—[AMENDED]

1. The authority citation for part 1700 continues to read as follows:

Authority: Pub. L. 91–601, secs. 1–9, 84 Stat. 1670, 15 U.S.C. 1471–76, Secs. 1700.1 and 1700.14 also issued under Pub. L. 92–573, sec. 30(a), 88 Stat. 1231, 15 U.S.C. 2079(a).

2. Section 1700.14(a)(13) is revised to read as follows:

§ 1700.14 Substances requiring special packaging.

(a) * * *

(13) *Dietary supplements containing iron*. Dietary supplements, as defined in § 1700.1(a)(3), that contain an equivalent of 250 mg or more of elemental iron, from any source, in a single package in concentrations of 0.025 percent or more on a weight-to-volume basis for liquids and 0.05 percent or more on a weight-to-weight basis for nonliquids (e.g., powders, granules, tablets, capsules, wafers, gels, viscous products, such as pastes and ointments, etc.) shall be packaged in accordance with the provisions of § 1700.15 (a), (b), and (c), except for the following:

(i) Preparations in which iron is present solely as a colorant; and

(ii) Powdered preparations with no more than the equivalent of 0.12 percent weight-to-weight elemental iron.

* * * * *

Dated: April 3, 1995.

Sadye E. Dunn,

Secretary, Consumer Product Safety Commission.

Reference Documents

The following documents contain information relevant to this rulemaking proceeding and are available for inspection at the Office of the Secretary, Consumer Product Safety Commission, Washington, Room 502, 4330 East-West Highway, Bethesda, Maryland 20814.

1. Briefing Memorandum with attached briefing package, March 14, 1995.
2. Memorandum from Sandra E. Inkster, Ph.D., HSPS, to Jacqueline N. Ferrante, Ph.D., HSPS, ''Review of Iron Toxicity: Relevance to a Petition Requesting Exemption for Powdered, Iron-Containing Dietary Supplements,'' February 15, 1995.
3. Memorandum from Catherine A. Sedney, EPHF, to Jacqueline N. Ferrante, Ph.D., HSPS, ''Petition to Exempt Iron-Containing Supplement Powders from PPPA Requirements,'' February 16, 1995.
4. Memorandum from Marcia P. Robins, EPSS, to Jacqueline N. Ferrante, Ph.D., HSPS, ''Preliminary Market Information: Petition for Exemption from Child-Resistant Packaging Requirements for Powdered Iron-Containing Dietary Supplements,'' March 10, 1995.

[FR Doc. 95–8522 Filed 4–6–95; 8:45 am]

BILLING CODE 6355–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket Nos. RM95–8–000 and RM94–7–001]

Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking

March 29, 1995.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking and supplemental notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to require that public utilities owning and/or controlling facilities used for the transmission of electric energy in interstate commerce have on

file tariffs providing for non-discriminatory open access transmission services. The Commission is also proposing to permit public utilities and transmitting utilities to recover legitimate and verifiable stranded costs. The Commission's goal is to encourage lower electricity rates by structuring an orderly transition to competitive bulk power markets. The Commission is seeking public comment on its proposals.

DATES: Written comments must be received by the Commission by August 7, 1995. Reply comments must be received by the Commission by October 4, 1995.

FOR FURTHER INFORMATION CONTACT:

David D. Withnell, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol St., NE., Washington, DC 20426, telephone: (202) 208–2063, (Docket No. RM95–8–000—legal issues).

Deborah B. Leahy, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, telephone: (202) 208–2039, (Docket No. RM94–7–001—legal issues).

Michael A. Coleman, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, telephone: (202) 208–1236, (technical issues).

ADDRESSES: Send comments to: Office of the Secretary Federal Energy Regulatory Commission 825 North Capitol Street, N.E. Washington, D.C. 20426.

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 3401, at 941 North Capitol Street, NE., Washington, DC 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing (202) 208–1397. To access CIPS, set your communications software to 19200, 14400, 12000, 9600, 7200, 4800, 2400, 1200 or 300bps, full duplex, no parity, 8 data bits and 1 stop bit. The full text of this document will be available on CIPS for 60 days from the date of issuance in ASCII and WordPerfect 5.1 format. After 60 days the document will be archived, but still accessible. The complete text on diskette in WordPerfect format may also be purchased from the Commission's copy contractor, La Dorn Systems Corporation, also located in room 3104, 941 North Capitol Street, NE., Washington, DC 20426.

Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities

Docket No. RM95–8–000

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

Docket No. RM94–7–001

Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking

March 29, 1995.

Table of Contents

I. Introduction

The electric power industry is today an industry in transition. In response to changes in the law, technology, and markets, competitive pressures are steadily building in the industry. Once the primary domain of large, vertically integrated utilities providing power at regulated rates, the industry now includes companies selling ''unbundled'' power at rates set by competitive markets. New generating facilities are being built at costs well below the average costs of some vertically integrated utilities. In this environment, more competition will mean lower rates for wholesale customers and, ultimately, for consumers.

The Commission's goal is to encourage lower electricity rates by structuring an orderly transition to competitive bulk power markets. Development of such markets is certain. The questions are when and how. Experience has shown that competitive pressures cannot be contained for long without serious economic distortions. Competition will, we are confident, result in lower rates. But experience has also shown that a measured transition from regulated to competitive markets is absolutely essential.

Moving to competitive generation markets will fundamentally change long-standing regulatory relationships. Utilities have invested billions of dollars in order to meet their obligations. Those investments have been made under a ''regulatory compact'' whereby utilities—and their shareholders—expect to recover prudently incurred costs. With the advent of competition, even prudent investments may become stranded. Reliance on past contractual and regulatory practices must be recognized and past investments must be protected to assure an orderly, fair transition to competition.

The focus of our proposal today is to facilitate competitive wholesale electric power markets. The key to competitive bulk power markets is opening up transmission services. Transmission is the vital link between sellers and buyers. To achieve the benefits of robust, competitive bulk power markets, all wholesale buyers and sellers must have equal access to the transmission grid. Otherwise, efficient trades cannot take place and ratepayers will bear unnecessary costs. Thus, market power through control of transmission is the single greatest impediment to competition. Unquestionably, this market power is still being used today, or can be used, discriminatorily to block competition.

The Commission has an obligation to prevent unduly discriminatory practices in transmission access. In current circumstances, the absence of tariffs offering open access, non-discriminatory transmission services by each public utility impedes the transition to competitive markets greatly enough to be unduly discriminatory under section 206 of the Federal Power Act (FPA). Proceeding as we have in the past, case-by-case, would delay unreasonably the transition to competitive markets. A patchwork of transmission systems—some open and some not—would also lead to unfair practices and inequitable burdens.

At the same time, while fulfilling our duty under section 206 of the FPA to cure undue discrimination, we see no need now to abrogate existing contractual relationships. Rather, we propose to provide a transition to a competitive generation industry that allows for the recovery of legitimate, prudent and verifiable costs lawfully incurred to serve customers under the terms of existing contracts. In the context of today's electric industry, the goals of increased competition and lower bulk power rates are best pursued through a structured transition rather than through abrogating all existing contracts.

In short, at this crossroad for the industry, it is critical to take the regulatory steps now to facilitate the transition to competitive bulk power markets in an orderly manner. The most important of these steps are to ensure non-discriminatory access to the transmission grid for all wholesale buyers and sellers of electric energy in interstate commerce, and to address the transition costs associated with open transmission access. The Commission will take these steps in a manner consistent with maintaining the reliability of the interstate transmission grid.

In this proceeding, the Commission pursuant to its authority under sections 205 and 206:

- proposes to require all public utilities owning or controlling facilities used for transmitting electric energy in interstate commerce to file open access transmission tariffs;
- proposes to require the utilities to take transmission service (including ancillary services) for their own wholesale sales and purchases of electric energy under the open access tariffs;
- issues a supplemental proposed rule to permit the recovery of legitimate and verifiable stranded costs associated with requiring open access tariffs; and
- proposes regulations to implement the filing of the open access tariffs and the initial rates under these tariffs.

The open access tariffs—to be offered to all sellers and buyers of electric energy sold at wholesale in interstate commerce—must offer wholesale transmission services (network and point-to-point), including ancillary services, on a non-discriminatory basis to third parties.[1] In addition, the public utility must price separately all wholesale generation and transmission services (including ancillary services) and take wholesale transmission service under its own tariff, *i.e.*, ''functionally unbundle'' its wholesale generation and transmission services. The proposed rule does not mandate the corporate separation of generation, transmission, and distribution functions.

The proposed rule proposes *pro forma* tariffs for network and point-to-point services, defines non-discriminatory open access to include access to ancillary services, and requires that tariffs include a reciprocity provision requiring any user or agent of the user of the tariff that owns and/or controls transmission facilities to provide non-discriminatory access to the tariff provider.

To assure that the open access tariffs promote competition and do not operate in an unduly discriminatory manner, the proposed rule would require public utilities to provide all actual or potential transmission users the same access to information as the public utility enjoys. The Commission is proposing to develop industry-wide real-time information networks in a separate Notice of Technical Conference that is being issued concurrently with this proposed rule.[2]

Not all transmitting utilities are public utilities subject to the Commission's jurisdiction under section 206 of the FPA.[3] The Commission cannot pursuant to section 206 require non-public utilities to file open access tariffs . Therefore, the proposed rule would encourage the broad application of section 211 as an additional means of achieving the goal in the Energy Policy Act of 1992 of promoting increased wholesale competition. Without broader application of section 211, wholesale bulk power market participants could be denied access to more competitive generation sources to the detriment of consumers.

We presently do not find it necessary to use our authority under section 206 of the FPA to reform public utilities' existing requirements contracts or any other contracts to eliminate undue discrimination or attain more competitive bulk power markets. However, we seek information about existing requirements contracts, including the remaining life and notice provision in each such contract, and whether it would be in the public interest to modify any existing contracts.

The Commission believes that the open access requirement will eliminate the transmission market power of public utilities by ensuring that all participants in wholesale power markets will have non-discriminatory open access to the transmission systems of public utilities. This market power has been the Commission's primary concern in recent years in analyzing requests for market-based generation rates. We therefore seek comments on the effect of industry-wide non-discriminatory open access on the Commission's criteria for authorizing power sales at market-based rates.

The Commission's market-rate criteria also have included other aspects of market power, such as generation dominance. In particular, we note the Commission's recent *KCP&L* decision, in which we dropped the generation dominance standard for market-based sales from new capacity.[4] This rule proposes to codify that decision, and seeks comment on whether the generation dominance standard should also be dropped for market-based sales from existing capacity.

In issuing this proposed rule, we are particularly concerned with its possible effect on stranded costs. It is important

[1] Throughout this NOPR this requirement will be referred to as the ''non-discriminatory open access'' requirement.

[2] Notice of Technical Conference and Request for Comments, Docket No. RM95–9–000.

[3] Section 206 of the FPA applies to public utilities, whereas section 211 applies to transmitting utilities. 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).'' 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.'' Not all transmitting utilities are public utilities. For instance, a municipally-owned electric utility that owns transmission facilities that are used for the sale of electric energy at wholesale is a transmitting utility, but is not a public utility.

[4] See Kansas City Power & Light Company, 67 FERC ¶ 61,183 at 61,557 (1994) (*KCP&L*).

to couple our open access rule with a rule ensuring recovery of all legitimate transition costs, consistent with the guidelines established herein. Accordingly, we are making preliminary findings with respect to the Stranded Cost NOPR issued on June 29, 1994, seeking additional comments, and consolidating the Stranded Cost NOPR [5] with this proposed rule.

Because of the benefits associated with the transition to a competitive regime, it is important to have the open access tariffs in place as soon as possible. Thus, we propose a two-stage procedure to accomplish that goal. In Stage One, we would place generic open access tariffs in effect simultaneously on a date certain for every public utility that owns and/or controls transmission facilities [6] and would establish rates for each public utility based on the most current Form No. 1 data available. In Stage Two, utilities would be free to propose changes to the rates, terms, and conditions in the generic tariffs and customers and others would be free to file complaints seeking changes in the rates, terms, and conditions. However, Stage Two tariffs must contain at least the non-price tariff terms and conditions contained in the *pro forma* tariffs.

Comments of all interested persons should be filed pursuant to the procedures set out below.

II. Public Reporting Burden

A. Docket No. RM95–8–000

The proposed rule specifies filing requirements to be followed by public utilities in making non-discriminatory open access tariff filings. The information collection requirements of the proposed rule are attributable to FERC–516 ''Electric Rate Filings.'' The current total annual reporting burden for FERC–516 is 784,488 hours.

The proposed rule requires public utilities filing non-discriminatory open access tariffs to provide certain information to the Commission. The public reporting burden for the information collection requirements contained in the proposed rule is estimated to average 300 hours per response. This estimate includes time for reviewing the requirements of the Commission's regulations, searching existing data sources, gathering and maintaining the necessary data, completing and reviewing the collection of information, and filing the required information.

There are approximately 328 public utilities, including marketers and wholesale generation entities. The Commission estimates that approximately 137 of these utilities own or control facilities used for the transmission of electric energy in interstate commerce and will respond to the information collection. The respondents would be all public utilities required to file non-discriminatory open access tariffs. These are the public utilities that are also transmitting utilities and either file Form 715 or have it filed on their behalf. The information will be provided with each filing by a respondent. Accordingly, the public reporting burden is estimated to be 41,100 hours.

Send comments regarding this burden estimate or any other aspect of the Commission's collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 941 North Capitol Street NE., Washington, DC 20426 [Attention: Michael Miller, Information Services Division, (202) 208–1415], and to the Office of Information and Regulatory Affairs of the Office of Management and Budget [Attention: Desk Officer for Federal Energy Regulatory Commission (202) 395–3087].

B. Docket No. RM94–7–001

The initially proposed rule would require public utilities seeking to recover stranded costs to provide certain information to the Commission. The Commission estimated that the public reporting burden for the information collection requirements contained in the initially proposed rule would be 50 hours per response. The Commission also estimated that there would be ten respondents to the information collection annually.

Under the proposed rule contained in this supplemental notice of proposed rulemaking, the information that public utilities will be required to file is not substantially different from that required by the initially proposed rule. The Commission also believes that the average filing burden and frequency of filing will be approximately the same as under the initially proposed rule. Therefore, the Commission estimates that there will be no additional public filing burden associated with the proposed rule.

Send comments regarding this burden estimate or any other aspect of the Commission's collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 941 North Capitol Street, NE., Washington, DC 20426 [Attention: Michael Miller, Information Services Division, (202) 208–1415], and to the Office of Information and Regulatory Affairs of the Office of Management and Budget [Attention: Desk Officer for Federal Energy Regulatory Commission (202) 395–3087].

III. Discussion

A. Summary of Authority and Findings

The primary purposes of the Federal Power Act are to curb abusive practices by public utility companies and to protect consumers from excessive rates and charges. To achieve these ends, section 205 of the FPA requires that no public utility shall ''make or grant any undue preference or advantage to any person or subject any person to any undue preference or disadvantage,'' with respect to the transmission of electric energy in interstate commerce or the sale for resale of electric energy in interstate commerce. [7] Section 206 of the FPA authorizes the Commission to investigate and remedy unduly discriminatory or preferential rules, regulations, practices or contracts affecting public utility rates for transmission in interstate commerce or for sales for resale in interstate commerce.

The significant technological, structural, statutory, and regulatory changes over the past twenty years have affected the electric utility industry such that competitive bulk power markets are now emerging. This transition has expanded what the Commission must consider to be undue discrimination in the rates, terms, and conditions offered by public utilities. We find that utilities owning or controlling transmission facilities possess substantial market power; that, as profit maximizing firms, they have and will continue to exercise that market power in order to maintain and increase market share, and will thus deny their wholesale customers access to competitively priced electric generation; and that these unduly discriminatory practices will deny consumers the substantial benefits of lower electricity prices. We propose to prevent this discrimination by requiring all public utilities owning and/or controlling transmission facilities to offer non-discriminatory open access transmission services.

At the same time, we see no need now to abrogate existing contractual relationships. Instead, contracts should

[5] See Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, 59 FR 35274 (July 11, 1994), IV FERC Stats. & Regs., Proposed Regulations ¶ 32,507 (Stranded Cost NOPR).

[6] Because power pools raise complex issues, we seek comments on how to implement the NOPR for power pools.

[7] 16 U.S.C. 824d(b) and 824(d).

be permitted to run their course. Additionally, we believe that recovery of legitimate stranded costs is critical to the successful transition of the electric utility industry from a tightly regulated, cost-of-service utility industry to an open access, competitively priced power industry.

The requirement of open access coupled with the recovery of legitimate stranded costs furthers the Congressional purposes embodied in the Federal Power Act and the Energy Policy Act of 1992 of protecting consumers, ensuring reasonable rates, and encouraging competition.

Below, we set out the Commission's legal authority to require non-discriminatory open access, the relevant historical developments in the electric industry, and the need for regulatory reform. [8]

B. Legal Authority

1. Undue Discrimination/ Anticompetitive Effects

The Commission has authority to remedy undue discrimination. That is clear. Some may argue that case law under the FPA limits our authority to order wheeling. We have carefully analyzed relevant cases examining our wheeling authority. We conclude that we have authority to require wheeling, or non-discriminatory open access, as a remedy for undue discrimination. Our analysis of the case law is set forth below.

In upholding the Commission's order requiring non-discriminatory open access in the natural gas industry, the court in *Associated Gas Distributors* v. *FERC* stated that the Natural Gas Act ''fairly bristles'' with concern for undue discrimination.[9] The same is true of the FPA. The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. As discussed below, *AGD* demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access as a remedy for undue discrimination. Moreover, the Commission's power under the FPA ''clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to [FPA] sections 202 and 203, and under like directives contained in sections 205, 206, and 207.'' [10]

Based on the mandates of sections 205 and 206 of the FPA and the case law interpreting the Commission's authority over transmission in interstate commerce, we conclude that we have ample legal authority—indeed, a responsibility—under section 206 of the FPA to order the filing of non-discriminatory open access transmission tariffs if we find such order necessary as a remedy for undue discrimination or anticompetitive effects.[11] We discuss below the primary court decisions that touch on our wheeling authority under sections 205 and 206.

The Commission's authority to order access as a remedy for undue discrimination under the NGA was upheld and discussed in detail in *AGD*. In *AGD*, the court upheld in relevant part the Commission's Order No. 436.[12] That order found the prevailing natural gas company practices to be ''unduly discriminatory'' within the meaning of section 5 of the NGA (the parallel to section 206 of the FPA) and held that if pipelines wanted blanket certification for their transportation services, they must commit to transport gas for others on a non-discriminatory basis; in other words, they must provide non-discriminatory open access.

In upholding the Commission's authority to require open access, the court first noted that the opponents' arguments against such authority were ''uphill.'' The statute contains no language forbidding the Commission to impose common carrier status on pipelines, let alone forbidding the Commission to impose ''a specific duty that happens to be a typical or even core component of such status.'' The court found that the legislative history cited by the opponents came nowhere near overcoming this statutory silence. Rather, the legislative history supported only the proposition that Congress itself declined to impose common carrier status.[13] Emphasizing Congress' deep concern with undue discrimination, the court found that the Commission had ample authority to ''stamp out'' such discrimination:

> The issue seems to come down to this: Although Congress explicitly gave the Commission the power and the duty to achieve one of the prime goals of common carriage regulation (the eradication of undue discrimination), the Commission's attempted exercise of that power is invalid because Congress in 1906 and 1914 and 1935 and 1938 itself refrained from affixing common carrier status directly onto the pipelines and from authorizing the Commission to do so. And this proposition is said to control no matter how sound the Order may be as a response to the facts before the Commission. We think this turns statutory construction upside down, letting the failure to grant a general power prevail over the affirmative grant of a specific one.[14]

The *AGD* court found that court decisions under the FPA did not support the view that the Commission's authority to ''stamp out'' undue discrimination is hamstrung by an inability to require non-discriminatory open access as a remedy. These decisions are discussed below.

One of the earliest cases on wheeling is *Otter Tail Power Company* v. *United States (Otter Tail)*[15] That case was a civil antitrust suit against an electric utility. The Court rejected the argument that the District Court could not order wheeling because to do so would conflict with the Federal Power Commission's (FPC) purported wheeling authority.[16] It pointed out that Congress had decided not to impose a common carrier obligation on the electric power industry and noted that the Commission was not at that time granted power to order wheeling. The *Otter Tail* case, however, did not address whether the Commission can require transmission in fulfillment of its duty to remedy undue discrimination.

Richmond Power & Light Company v. *FERC* (*Richmond*)[17] also did not involve

[8] On February 16, 1995, the Coalition for a Competitive Electric Market filed a petition for a rulemaking on comparability. The Industrial Consumers and the Transmission Access Policy Study Group filed comments in support of the petition. The Commission will not separately notice the Coalition's petition, but seeks comment on that pleading, and the supporting pleadings, in this notice of proposed rulemaking.

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

[10] See *Gulf States Utilities Company* v. *FPC,* 411 U.S. 747, 758–59 (1973).

[11] In most situations, discrimination that precludes transmission access or gives inferior access will have at least potential anticompetitive effects because it limits access to generation markets and thereby limits competition in generation. Similarly, it is probable that any transmission provision that has anticompetitive effects would also be found to be unduly discriminatory or preferential because the anticompetitive provision would most likely favor the transmission owner *vis-a-vis* others.

[12] Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, III FERC Stats. & Regs., Regulations Preambles ¶ 30,665 (1985).

[13] *AGD, supra,* 824 F.2d at 997.

[14] *Id.* at 998.

[15] 410 U.S. 366 (1974).

[16] *Id.* at 375–76.

[17] 574 F.2d 610 (D.C. Cir. 1978).

requiring wheeling to remedy undue discrimination. In that case, the FPC, in reaction to the 1973 oil embargo, was attempting to reduce dependence on oil. The FPC requested that utilities with excess capacity wheel power to the New England Power Pool (NEPOOL). In response, several suppliers and transmission owners filed rate schedules with the FPC that provided for voluntary wheeling. Richmond Power & Light Company (Richmond) objected to these filings, claiming that they were unreasonable because they did not guarantee transmission access. The FPC refused to compel the utilities to wheel Richmond's power, stating that it did not have the authority to order a public utility to act as a common carrier.

The D.C. Circuit upheld the Commission. It acknowledged that Richmond's argument was persuasive in some respects, but stated that any conditions the Commission might impose could not contravene the FPA. The court examined the legislative history of the FPA and stated that ''[i]f Congress had intended that utilities could inadvertently bootstrap themselves into common-carrier status by filing rates for voluntary service, it would not have bothered to reject mandatory wheeling * * *.'' [18]

However, the D.C. Circuit in no way indicated that the Commission was foreclosed from ordering transmission as a remedy for undue discrimination. Richmond also had argued that the alleged refusal of the American Electric Power Company (AEP) and its affiliate, Indiana & Michigan Electric Company (Indiana), to wheel Richmond's excess energy was unlawful discrimination because AEP and Indiana wheeled higher-priced electricity from other AEP affiliates. The court acknowledged that Richmond's claim of unlawful discrimination was theoretically valid, but found that Richmond had failed to prove its case. It noted that if Richmond had argued that the rates were unjustifiably discriminatory, or that Indiana's failure to use its transmission capability fully or to purchase less expensive electricity for wheeling resulted in unnecessarily high rates, a different case would be before the court.[19] The case thus does not in any way limit the Commission's authority to remedy undue discrimination.

In *Central Iowa Power Cooperative* v. *FERC*,[20] the FPC [21] reviewed the terms of the Mid-Continent Area Power Pool (MAPP) Agreement under its section 205 and 206 authority. The agreement contained two membership limitations. First, the agreement established two classes of membership, with one class being entitled to more privileges than the other. Second, the agreement excluded non-generating distribution systems from pool services. The FPC found the first limitation on membership—the two-class system—to be unduly discriminatory and not reasonably related to MAPP's objectives. The FPC conditioned approval of the agreement under section 206 on the removal of the unduly discriminatory provision. The FPC found that the second limitation, the exclusion of non-generating distribution systems, was not anticompetitive and did not render the agreement inconsistent with the public interest.

On appeal, the D.C. Circuit affirmed the FPC's decision. The court found that the FPC did have authority to order changes in the scope of the MAPP agreement, *if* the agreement was unjust, unreasonable, unduly discriminatory or preferential under section 206 of the FPA. The court stated:

> The Commission had authority, * * * under section 206 of the Act, * * * to order changes in the limited scope of the Agreement, including the addition of pool services, if, in the absence of such modifications, the Agreement presented ''any rule, regulation, practice or contract [that was] unjust, unreasonable, unduly discriminatory or preferential.'' [22]

However, the court agreed with the FPC's conclusion that the limited scope of MAPP was not unjust, unreasonable, or unduly discriminatory. The court recognized that a pool was not invalid under section 206 merely because a more comprehensive arrangement was possible.

The D.C. Circuit upheld the Commission's refusal to eliminate the second limitation on membership by ordering MAPP participants to wheel to non-generating electric systems.[23] However, neither the Commission nor the court was presented with the argument that wheeling was necessary as a remedy for undue discrimination.

In *Florida Power & Light Company* v. *FERC* (*Florida*),[24] the Commission ordered Florida Power & Light Company (FP&L) to file a tariff setting forth FP&L's policy relating to the availability of transmission service.[25] FP&L objected to including such a policy statement in its tariff and argued that the filing of such a policy would convert FP&L into a common carrier by obligating it to offer service to all customers.[26] There was no finding that the action ordered was necessary to remedy undue discrimination.

The Fifth Circuit Court of Appeals agreed with FP&L that the mandatory filing of the policy statement would require FP&L to provide transmission service beyond its voluntary commitment because such a requirement would change its duties and liabilities.[27] The Commission order would impose common carrier status on FP&L, the court found.[28] The court noted that the Commission did not rely on a finding of anticompetitive behavior and therefore the court did not address the Commission's power to remedy antitrust violations.[29]

The *AGD* court explicitly rejected the claim that the above line of cases establishes that the Commission lacks authority to require non-discriminatory open access.[30] Opponents of the Commission's order argued in *AGD* that *Richmond* and *Florida*, *supra,* stand for the proposition that the Commission cannot indirectly do what it allegedly cannot do directly, that is, impose common carriage. The *AGD* court rejected these arguments, stating that

---

[18] *Id.* at 620.

[19] *Id.* at 623, nn. 53 and 57.

[20] 606 F.2d 1156 (D.C. Cir. 1979).

[21] While *Central Iowa* was pending, certain of the functions of the FPC were transferred to the FERC under the DOE Organization Act. Accordingly, the FERC was substituted for the FPC as the respondent in the case.

[22] 606 F.2d at 1168.

[23] *Id.* at 1169; see also *Municipalities of Groton* v. *FERC*, 587 F.2d 1296 (D.C. Cir. 1978).

[24] 660 F.2d 668 (5th Cir. 1981), *cert. denied sub nom. Fort Pierce Utilities Authority* v. *FERC*, 459 U.S. 1156 (1983).

[25] FP&L provided transmission service when four conditions were met: (1) The specific potential seller and buyer were contractually identified; (2) the magnitude, time and duration of the transaction were specified prior to the commencement of the transmission; (3) it could be determined that the transmission capacity would be available for the term of the contract; and (4) the rate was sufficient to cover FP&L's costs.

[26] All utilities requesting wheeling services, subject to availability, would be entitled to receive transmission service under the filed terms. Any changes to a filed rate must be filed with the Commission. This is the so-called ''filed rate doctrine.'' See Northwestern Public Service Company v. Montana-Dakota Utilities Company, 181 F.2d 19, 22 (8th Cir. 1980), *aff'd*, 341 U.S. 246 (1951).

[27] Under the filed rate doctrine, a refusal to wheel would be unduly discriminatory under section 206 of the FPA. As the court acknowledged, a customer refused service could petition the Commission to find that FP&L's policy of availability was unduly discriminatory under section 206(a) of the FPA. The court said that in the absence of a tariff on file, a utility refused wheeling services would be unable to claim discrimination under section 206(a) of the FPA. 660 F.2d at 675 (expressing ''serious doubts that such a petition would be successful in the absence of a tariff'').

[28] *Id.* at 676.

[29] *Id.* at 678.

[30] The *AGD* court did not address *New York State Electric & Gas Corporation* v. *FERC*, 638 F.2d 388 (2d Cir. 1980), *cert. denied*, 454 U.S. 821 (1981) (*NYSEG*), presumably because that case did not concern whether the Commission could order wheeling as a remedy for undue discrimination.

the petitioners read the electric cases far too broadly:

> [n]either *Richmond* nor *Florida* comes anywhere near stating that the Commission is barred from imposing an open-access condition in all circumstances. [31]

The court noted that the *Florida* case had expressly left open the question of whether the Commission would be entitled to use an open access condition as a remedy for anticompetitive conduct, and that in *Richmond* the D.C. Circuit had said little more than that unwillingness to transmit for all could not be automatically deemed undue discrimination. The court also noted the *Central Iowa* case, *supra*, in which it had upheld a Commission order that found a power pooling agreement discriminatory on its face because the agreement gave one class of membership privileged status over another. The court stated that the *Central Iowa* case ''upholds the power of the Commission to subject approval of a set of voluntary transactions to a condition that providers open up the class of permissible users.'' [32] The court added that it refused to ''turn statutory construction upside down'' by letting Congress' failure to grant a general power of common carriage prevail over the affirmative grant of the specific power to eradicate undue discrimination.[33]

We conclude that *AGD*'s analysis of undue discrimination under sections 4 and 5 of the Natural Gas Act is equally applicable to an undue discrimination analysis under sections 205 and 206 of the FPA. The Commission and courts have long recognized that the NGA was patterned after the FPA and that the two statutes should be interpreted in the same manner.[34] Thus, we conclude that we have the authority to remedy undue discrimination and anticompetitive effects by requiring all public utilities that own and/or control transmission facilities to file non-discriminatory open access transmission tariffs.

2. Section 211 Services

In concluding that we must invoke our section 206 authority to remedy undue discrimination and anticompetitive actions in the electric industry, we have carefully considered the goals of Title VII of the Energy Policy Act, and whether section 211, by itself, is sufficient to remedy undue discrimination in public utility transmission services.[35] Title VII of the Energy Policy Act, which amended section 211 of the FPA, reflects the intent of Congress to encourage competitive wholesale electric markets. Section 211 provides a means for wholesale power sellers and buyers to obtain transmission services necessary to compete in, or to reach, competitive markets, and is a valuable tool to encourage competitive markets. However, as discussed below, reliance on section 211 alone in some circumstances can result in the perpetuation of, rather than the elimination of, undue discrimination and anticompetitive effects.

First, there are inherent delays in the procedures for obtaining service under section 211. However, for competitive reasons, many transactions must be negotiated relatively quickly. Many competitive opportunities will be lost by the time the Commission can issue a final order under section 211. While we interpret section 211 to permit a customer or group of customers to seek broad tariff-like arrangements,[36] case-by-case section 211 proceedings are not a substitute for tariffs of general applicability that permit timely, non-discriminatory access on request.

Second, discrimination is inherent in the current industry environment in which some customers and sellers are served by open access systems, and others have to rely on negotiated bilateral arrangements or the mandatory section 211 process. The end result is discrimination in the ability to obtain transmission services, as well as in the quality and prices of the services. This national patchwork of open and closed transmission systems cannot be cured effectively through section 211.

The Commission believes that its actions under sections 205 and 206 will complement the section 211 procedures in achieving the goals of creating more competitive bulk power markets and lower rates for consumers, while avoiding many years of costly and unnecessary litigation. Section 211 will be particularly important for developing non-discriminatory access by non-public utilities.

C. Background

1. Structure of the Electric Industry at Enactment of Federal Power Act

The Federal Power Act was enacted in an age of mostly self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered limited service areas. This structure of separate systems arose naturally due primarily to the cost and technological limitations on the distance over which electricity could be transmitted.

Through much of the 1960s, utilities were able to avoid price increases, but still achieve increased profits, because of substantial increases in scale economies, technological improvements, and only moderate increases in input prices.[37] Thus, there was no pressure on regulatory commissions to use regulation to affect the structure of the industry.[38]

2. Significant Changes in the Electric Industry

In the late 1960s and throughout the 1970s, a number of significant events occurred in the electric industry that changed the perceptions of utilities and began a shift to a more competitive marketplace for wholesale power.[39] This was the beginning of periods of rapid inflation, higher nominal interest rates, and higher electricity rates.[40] During

---

[31] 824 F.2d at 999.

[32] *Id.* at 999.

[33] *Id.* at 1006.

[34] *See, e.g., FPC* v. *Sierra Pacific Power Company*, 350 U.S. 348, 353 (1956); *Arkansas Louisiana Gas Company* v. *Hall*, 453 U.S. 571, 577 n.7 (1981); and *Kentucky Utilities Company* v. *FERC*, 760 F.2d 1321, 1325 n.6 (D.C. Cir. 1985). Section 206 of the FPA was recently revised and now differs from section 5 of the NGA, but not in a manner significant to our discussion here. See 16 U.S.C. 824e(b) and (c).

[35] In amending section 211 Congress left unaltered the authorities and obligations of the Commission under sections 205 and 206 (similar to our authorities and obligations under sections 4 and 5 of the Natural Gas Act) to remedy undue discrimination.

[36] See *El Paso Electric Company and Central and South West Services Inc.*, 68 FERC ¶ 61,181 at 61,916 (1994) (*CSW*), *reh'g pending.*

[37] Paul L. Joskow, Inflation and Environmental Concern: Structural Change in the Process of Public Utility Regulation, 17 J. Law & Econ. 291, 312 (1974); see also Charles F. Phillips, Jr., The Regulation of Public Utilities 11 (1988).

[38] See Joskow, *supra* note 37, at 312; see also Phillips, *supra* note 37, at 12.

[39] See Joskow, *supra* note 37, at 312; see also Phillips, *supra* note 37, at 12–13.

[40] See Joskow, *supra* note 37, at 312–13; see also Phillips, *supra* note 37, at 13. The Arab oil embargo resulted in significantly higher oil prices through the 1970s. See Richard J. Pierce, Jr., The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity, 132 U. Pa. L. Rev. 497, 501 (1984).

this time, consumers became concerned about higher electricity rates and questioned any price increases filed by utilities.[41]

During this same time frame, the construction of nuclear and other capital-intensive baseload facilities—actively encouraged by federal and some state governments—contributed to the continuing cost increases and uncertainties in the industry.[42] These investments were made based on the assumptions that there would be steady increases in the demand for electricity and continued large increases in the price of oil.[43] However, due to conservation and economic downturns, the expected demand increases did not materialize. Load growth virtually disappeared in some areas, and many utilities unexpectedly found themselves with excess capacity.[44] In addition, by the 1980s, the oil cartel collapsed, with a resulting glut of low-priced oil.[45] At the same time, inflation substantially increased the costs of these large baseload generating plants.[46] Surging interest rates further increased the cost of the capital needed to finance and capitalize these projects and completion schedules were significantly extended by, in part, more stringent safety and environmental requirements.[47]

As a result, expensive large baseload plants came onto the market or were in the process of being constructed, for which there was little or no demand. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25% after adjusting for general inflation.[48] Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86% after adjusting for inflation.[49] The rapidly increasing rates for electric power during this period, together with the opportunities provided by the Public Utility Regulatory Policies Act of 1978 (PURPA) (discussed *infra*), also prompted some industrial customers to bypass utilities by constructing their own generation facilities. This further exacerbated rate increases for remaining customers—primarily residential and commercial customers.

Consumers responded to these ''rate shocks'' by exerting pressure on regulatory bodies to investigate the prudence of management decisions to build generating plants, especially when construction resulted in cost overruns, excess capacity, or both. Between 1985 and 1992, writeoffs of nuclear power plants totalled $22.4 billion.[50] These writeoffs significantly reduced the earnings of the affected utilities.[51] Delays in obtaining rate increases to reflect the effects of inflation further reduced investor returns. Thus, many utilities became reluctant to commit capital to long-term construction decisions involving large scale generating plants.[52]

In addition to economic changes in the industry, significant technological changes in both generation and transmission have occurred since 1935. Through the 1960s, bigger was cheaper in the generation sector and the industry was able to capitalize on economies of scale to produce power at lower per-unit costs from larger and larger plants.[53] As a result, large utility companies that could finance and manage construction projects of larger scale had a price advantage over smaller utility companies and customers who might otherwise have considered building their own generating units. Scale economies encouraged power generation by large vertically-integrated utility companies that also transmitted and distributed power. Beginning in the 1970s, however, additional economies of scale in generation were no longer being achieved.[54] A significant factor was that larger generation units were found to need relatively greater maintenance and experience longer downtimes.[55] The electric industry faced the situation ''where the price of each incremental unit of electric power exceeded the average cost.'' [56] Bigger was no longer better.

Further dictating against larger generation units were advances in technologies that allowed scale economies to be exploited by smaller size units, thereby allowing smaller new plants to be brought on line at costs below those of the large plants of the 1970s and earlier. Such new technologies include combined cycle units and conventional steam units that use circulating fluidized bed boilers.[57]

The combined cycle generating plants generally use natural gas as their primary fuel. This technology has been made possible by the development of more efficient gas turbines, shorter construction lead times, lower capital costs, increased reliability, and relatively minimal environmental impacts.[58] Similarly, the circulating fluidized bed combustion boilers, fueled by coal and other conventional fuels, provide a more efficient and less polluting resource.

Today, ''the optimum size [of generation plants] has shifted from [more than 500 MW] (10-year lead time) to smaller units (one-year lead time) [in the 50- to 150-MW range].'' [59]

Indeed, smaller and more efficient gas-fired combined-cycle generation facilities can produce power on the grid at a cost between 3 and 5 cents per

[41] See Joskow, *supra* note 37, at 313; see also Phillips, *supra* note 37, at 13.

[42] See generally *Jersey Central Power & Light Company* v. *FERC,* 810 F.2d 1168, 1171 (D.C. Cir. 1987).

[43] *Id.*

[44] See Pierce, *supra* note 40, at 503. By 1983, the Department of Energy had estimated that the sunk costs for canceled nuclear plants alone amounted to $10 billion. *Id.* at 498.

[45] *Id.*

[46] See Bernard S. Black & Richard J. Pierce, Jr., The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry, 93 Col. L. Rev. 1339, 1346 (1993) (''Actual costs of nuclear power plants vastly exceeded estimates, sometimes by as much as 1000%.'').

[47] See Phillips, *supra* note 37, at 13. Fossil fuel-fired plants became subject to increased regulation as a result of the Clean Air Act of 1970, and its 1977 amendments. 42 U.S.C. 7401–7642. In 1971, nuclear plant licensing became subject to the environmental impact statement requirements of the National Environmental Policy Act of 1969. 42 U.S.C. 4332. Following the 1979 accident at the Three Mile Island nuclear plant, nuclear plants also became subject to additional safety regulations, resulting in higher costs. See Energy Information Administration, The Changing Structure of the Electric Power Industry 1970–1991 (March 1993) 35. Between 1976 and 1980, most states and many localities instituted laws governing power plant siting.

[48] Based on retail prices reported in Energy Information Administration (EIA), Monthly Energy Review, January 1995, Table 9.9 (Prices adjusted for inflation using the GDP Deflator (1987 = 100)).

[49] *Id.*

[50] See Black & Pierce, *supra* note 46, at 1346 (These writeoffs were ''about 17% of the book value of total 1992 utility investment.'').

[51] *Id.*

[52] *Id.* (''The high perceived risk of future disallowances reversed utilities' incentives to overinvest, and made utilities extremely reluctant to build new power plants.'').

[53] *See* Preston Michie, Billing Credits for Conservation, Renewable, and Other Electric Power Resources: an Alternative to Marginal-Cost-Based Power Rates in the Pacific Northwest, 13 Environmental Law 963, 964–65 (1983).

[54] *Id.* at 965.

[55] Energy Information Administration, The Changing Structure of the Electric Power Industry 1970–1991 (March 1993) 37 (''As larger units were constructed, however, utilities discovered that downtime was as much as 5 times greater for units larger than 600 megawatts than for units in the 100-megawatt range.'')

[56] *Id.;* see also George A. Perrault, Downsizing Generation: Utility Plans for the 1990s, Pub. Util. Fort. 15–16 (Sept. 27, 1990) (''The large base-load generating units that form the backbone of utility systems are almost totally absent from capacity plans for the 1990s.'').

[57] ''From 1982 through 1991, the average capacity of fluidized-bed units increased rapidly to 72 megawatts for 4 units in 1991. The average capacity for the 19 units planned to begin operating in 1992 through 1995 increases to 83 megawatts.'' Energy Information Administration, The Changing Structure of the Electric Power Industry 1970–1991 (March 1993) 38.

[58] See Charles E. Bayless, Less is More: Why Gas Turbines Will Transform Electric Utilities, Pub. Util. Fort. (Dec. 1, 1994) 21.

[59] *Id.* at 24.

kWh.[60] This is significantly less than the costs for large plants constructed and installed by utilities over the last decade, which were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.[61]

Significant changes have also occurred in the transmission sector of the industry. Technological advances in transmission have made possible the economic transmission of electric power over long distances at higher voltages.[62] This has made it technically feasible for utilities with lower cost generation sources to reach previously isolated systems where customers had been captive to higher cost generation. In addition, the nature and magnitude of coordination transactions[63] have changed dramatically since enactment of the FPA, allowing increased coordinated operations and reduced reserve margins. Substantial amounts of electricity now move between regions, as well as between utilities in the same region. Physically isolated systems have become a thing of the past.

3. The Public Utility Regulatory Policies Act and the Growth of Competition

In enacting PURPA,[64] Congress recognized that the rising costs and decreasing efficiencies of utility-owned generating facilities were increasing rates and harming the economy as a whole.[65] To lessen dependence on expensive foreign oil, avoid repetition of the 1977 natural gas shortage, and control consumer costs, Congress sought to encourage electric utilities to conserve oil and natural gas.[66] In particular, Congress sanctioned the development of alternative generation sources designated as ''qualifying facilities'' (QFs) as a means of reducing the demand for traditional fossil fuels.[67] PURPA required utilities to purchase power from QFs at a price not to exceed the utility's avoided costs and to sell backup power to QFs.[68]

PURPA specifically set forth limitations on who, and what, could qualify as QFs. In addition to technological and size criteria, PURPA set limits on who could own QFs.[69] Notwithstanding these limitations, QFs proliferated. In 1989, there were 576 QF facilities. By 1993, there were more than 1,200 such facilities.[70] For the same time period, installed QF capacity increased from 27,429 megawatts to 47,774 megawatts.[71] The rapid expansion and performance of the QF industry demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power.

During this period, the profile of generation investment began to change, and a market for non-traditional power supply beyond the purchases required by PURPA began to emerge. QFs were limited to cogenerators and small power producers.[72] However, other non-traditional power producers who could not meet the QF criteria began to build new capacity to compete in bulk power markets, without such PURPA benefits as the mandatory purchase requirements. These producers, known as independent power producers (IPPs), were predominantly single-asset generation companies that did not own any transmission or distribution facilities. While traditional utilities were generally reluctant at that time to invest in new generating facilities under cost of service regulation, utilities increasingly became interested in participating in this new generation sector. They organized affiliated power producers (APPs), with assets not included in utility rate base, and sought to sell power in their own service territories and the territories of other utilities. At the same time, power marketers arose. These entities—owning no transmission or generation—buy and sell power.[73]

There were two major impediments to the development of IPPs and APPs. First, the ownership restrictions of the Public Utility Holding Company Act (PUHCA)[74] severely inhibited these new entities from entering the generation business.[75] Second, these entities needed transmission service in order to compete in electricity markets.

While the Commission had no authority to remove PUHCA restrictions,[76] it encouraged the development of IPPs and APPs, as well as emerging power marketers, by authorizing market-based rates for their power sales on a case-by-case basis and

[60] FERC staff calculations based in part on combined-cycle plant cost data reported in 1993 FERC Form No. 1 for a sample of units placed in service during 1990–92. Costs vary with regional fuel and construction costs, among other reasons.

[61] Coal and Nuclear plant cost data reported in 1993 FERC Form No. 1 and the EIA report, Electric Plant Cost and Power Production Expenses 1991, 1993 DOE/EIA–0455 (91), for plants placed in service during 1986–93; see also The 1994 Electric Executives' Forum, Bakke (President and CEO of the AES Corporation), Pub. Util. Fort. (June 1, 1994) 45 (''New generation can be built at about 3 cents per kilowatt-hour (U.S. average). Old generation costs about twice that * * *'').

[62] See Black & Pierce, *supra* note 46, at 1345 (In the late 1960s and 1970s, improved transmission efficiency and development of regional transmission networks ''made it possible to build power plants up to 1000 miles from power users.'').

[63] Coordination transactions are voluntary sales or exchanges of specialized electricity services that allow buyers to realize cost savings or reliability gains that are not attainable if they rely solely on their own resources. For sellers, these transactions provide opportunities to earn additional revenue, and to lower customer rates, from capacity that is temporarily excess to native load capacity requirements.

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

[65] See generally *FERC* v. *Mississippi*, 456 U.S. 742, 745–46 (1982).

[66] The Power Plant and Industrial Fuel Use Act of 1978. Pub. L. 95–617, 92 Stat. 3117 (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

[67] QFs include certain cogenerators and small power producers. PURPA also added sections 210, 211 and 212 to the FPA, providing the Commission with authority to approve applications for interconnections and, in limited circumstances, wheeling. However, under section 211, as enacted in PURPA, the Commission could approve an application for wheeling only if it found, *inter alia*, that the order ''would reasonably preserve existing competitive relationships.'' Because of this and other limitations in sections 211 and 212 as originally enacted, the provision was virtually ineffective. Only one section 211 order was ever issued pursuant to the original provision, and it was pursuant to a settlement. See Public Service Company of Oklahoma, 38 FERC ¶61,050 (1987). As discussed *infra*, section 211 was subsequently revised by the Energy Policy Act of 1992.

[68] 456 U.S. at 750. Congress recognized that encouragement was needed in part because utilities had been reluctant to purchase electric power from, and sell power to, nonutility generators. *Id.* at 750–51.

[69] For example, PURPA provided that a cogeneration facility or small power production facility could not be owned by a person primarily engaged in the generation or sale of electric power (other than from cogeneration or small power production facilities). See 16 U.S.C. 796 (17) and (18).

[70] Energy Information Administration, Electric Power Annual 1993 (December 1994) 124 (Table 77).

[71] *Id*. EIA data for 1989 through 1991 was for facilities of 5 megawatts or more and for 1992 and 1993 was for facilities of 1 megawatt or more. A comparison with Table 74 on page 121 for the years 1992 and 1993 reveals that this mixing of data bases is likely of minimal effect.

[72] Generally, the law has imposed an 80 MW cap on small power producers. A limited exception enacted in 1990 permitted small power facilities that could exceed 80 MW and still qualify as QFs under PURPA. This exception was limited to certain solar, wind, waste, and geothermal small power production facilities and only covered applications for certification of facilities as qualifying small power production facilities that were submitted no later than December 31, 1994 and for which construction commences no later than December 31, 1999. See Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990, Pub. L. 101–575, 104 Stat. 2834 (1990), *amended*, Pub. L. 102–46, 105 Stat. 249 (1991).

[73] The first power marketer in the electric industry was Citizens Energy Corporation. See Citizens Energy Corporation, 35 FERC ¶ 61,198 (1986). Power marketers take title to electric energy. Power brokers, on the other hand, do not take title and are limited to a matchmaking role.

[74] 15 U.S.C. 79 *et seq.*

[75] As discussed *infra*, Congress eventually provided a means to avoid the PUHCA restrictions by creating exempt wholesale generators (EWGs) in the Energy Policy Act.

[76] The industry was successful to some extent in developing ownership structures that permitted such investment. See, e.g., Commonwealth Atlantic Limited Partnership, 51 FERC ¶ 61,368 at 62,240 and n.20 (1990).

by encouraging more widely available transmission access. From 1989 through 1993, facilities owned by IPPs and other non-traditional generators (other than QFs) increased from 249 to 634 and their installed capacity increased from 9,216 megawatts to 13,004 megawatts.[77] Indeed, ''[i]n 1992, for the first time, generating capacity added by independent producers exceeded capacity added by utilities.'' [78]

Market-based rates helped to develop competitive bulk power markets. A generating utility allowed to sell its power at market-based rates could move more quickly to take advantage of short-term or even long-term market opportunities than those laboring under traditional cost-of-service tariffs, which entail procedural delays in achieving tariff approvals and changes.

In approving these market-based rates, the Commission required, inter alia, that the seller and any of its affiliates lack market power or mitigate any market power that they may have possessed.[79] The major concern of the Commission was whether the seller or its affiliates could limit competition and thereby drive up prices. A key inquiry became whether the seller or its affiliates owned or controlled transmission facilities in the relevant service area and therefore, by denying access or imposing discriminatory terms or conditions on transmission service, could foreclose other generators from competing.[80] As we have previously explained:

The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive ownership of the facilities. However, market power also may be gained without ownership. Contracts can confer the same rights of control. Entities with contractual control over transmission facilities can withhold supply and extract monopoly prices just as effectively as those who control facilities through ownership.[81]

As entry into wholesale power generation markets increased, the ability of customers to gain access to the transmission services necessary to reach competing suppliers became increasingly important.[82] In addition, beginning in the late 1980s, public utilities seeking Commission approval of mergers or consolidations under section 203 of the FPA or Commission authorization for blanket approval of market-based rates for generation services under section 205 of the FPA, filed ''open access'' transmission tariffs of general applicability to mitigate their market power to meet Commission conditions.[83] The Commission applied its market rate analysis to IOUs, as well as IPPs, APPs, and marketers, and allowed IOUs to sell at market-based rates only if they opened their transmission systems to competitors.[84] The Commission also approved proposed mergers on the condition that the merging companies remedy anticompetitive effects potentially caused by the merger by filing ''open access'' tariffs. These early ''open access'' tariffs required only that the companies provide point-to-point transmission services, which is a much narrower requirement than that being proposed in this rule. However, only 21 public utilities have any form of open access transmission; the vast majority of IOUs still do not provide any form of ''open access'' transmission over their transmission systems.

The economic and technological changes in the transmission and generation sectors helped give impetus to the many new entrants in the generating markets who could sell electric energy profitably with smaller scale technology at a lower price than many utilities selling from their existing generation facilities at rates reflecting cost. However, the advantages of these technological advances can be achieved only if more efficient generating plants can obtain access to the regional transmission grids. Because the traditional vertically integrated utilities still favor their own generation if and when they provide transmission access to third parties, barriers continue to exist to cheaper, more efficient generation sources.

4. The Energy Policy Act

In response to the competitive developments following PURPA, and the fact that PUHCA and lack of transmission access [85] remained major barriers to new generators, Congress enacted Title VII of the Energy Policy Act of 1992 (Energy Policy Act).[86] A goal of the Energy Policy Act was to promote greater competition in bulk power markets by encouraging new generation entrants, known as exempt wholesale generators (EWGs), and by expanding the Commission's authority under sections 211 and 212 of the FPA to approve applications for transmission services.[87]

An EWG is defined as

any person determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly through one or more affiliates as defined in [PUHCA] section 2(a)(11)(B), and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale.[88]

If the Commission, upon an application, determines that a person is an EWG, that person will be exempt from PUHCA.[89] This provision removed a significant impediment to the development of IPPs and APPs by

[77] Energy Information Administration, Electric Power Annual 1993 (December 1994) 124 (Table 77).

[78] Black & Pierce, supra note 46, at 1349 n.25. possessed.

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

[80] See, e.g., Doswell, 50 FERC at 61,757.

[81] Citizens Power & Light Corporation, 48 FERC ¶ 61,210 at 61,777 (1989) (emphasis in original); see also Utah Power & Light Company, PacifiCorp and PC/UP&L Merging Corporation, 45 FERC ¶ 61,095 at 61,287–89 (1988), *order on reh'g*, 47 FERC ¶ 61,209, *order on reh'g*, 48 FERC ¶ 61,035 (1989), *remanded in part sub nom. Environmental Action, Inc.* v. *FERC*, 939 F.2d 1057 (D.C. Cir. 1991), *order on remand*, 57 FERC ¶ 61,363 (1991).

[82] In earlier years, a few customers were able to obtain access as a result of litigation, beginning with the Supreme Court's decision in *Otter Tail*, 410 U.S. 366 (1973). Additionally, some customers gained access by virtue of Nuclear Regulatory Commission license conditions and voluntary preference power transmission arrangements associated with federal power marketing agencies. See, *e.g.*, Consumers Power Company, 6 NRC 887, 1036–44 (1977) and The Toledo Edison Company and Cleveland Electric Illuminating Company, 10 NRC 265, 327–34 (1979). See *Florida Municipal Power Agency* v. *Florida Power and Light Company*, 839 F. Supp. 1563 (M.D. Fla. 1993). See also Electricity Transmission: Realities, Theory and Policy Alternatives, The Transmission Task Force Report to the Commission, October 1989, 197.

[83] *See, e.g.*, Public Service Company of Colorado, 59 FERC ¶ 61,311 (1992), *reh'g denied*, 62 FERC ¶ 61,013 (1993); Utah Power & Light Company, *et al.*, Opinion No. 318, 45 FERC ¶ 61,095 (1988), *order on reh'g*, Opinion No. 318–A, 47 FERC ¶ 61,209 (1989), *order on reh'g*, Opinion No. 318–B, 48 FERC ¶ 61,035 (1989), *aff'd in relevant part sub nom. Environmental Action Inc.* v. *FERC*, 939 F.2d 1057 (D.C. Cir. 1991); Northeast Utilities Service Company (Public Service Company of New Hampshire), Opinion No. 364–A, 58 FERC ¶ 61,070, *reh'g denied*, Opinion No. 364–B, 59 FERC ¶ 61,042, *order granting motion to vacate and dismissing request for rehearing*, 59 FERC ¶ 61,089 (1992), *affirmed in relevant part sub nom. Northeast Utilities Service Company* v. *FERC*, 993 F.2d 937 (1st Cir. 1993).

[84] See, *e.g.*, Public Service of Indiana, Inc., 51 FERC ¶ 61,367 (1990), *reh'g denied*, 52 FERC ¶ 61,260 (1990), *appeal dismissed sub nom. Northern Indiana Public Service Company* v. *FERC*, 954 F.2d 736 (D.C.Cir. 1992).

[85] See infra sections III.D.1 and 2.

[86] Pub. L. 102–486, 106 Stat. 2776 (1992).

[87] See El Paso Electric Company and Central and South West Services Inc., 68 FERC ¶ 61,181 at 61,914 (1994); see also Paul Kemezis, FERC's Competitive Muscle: The Comparability Standard, Electrical World 45 (Jan. 1995) (''In EPAct, Congress made it clear that the electric-power industry was to move toward a fully competitive market system, but left most of the implementation to FERC.'').

[88] 15 U.S.C. 79z–5a.

[89] 15 U.S.C. 79z–5a(e).

allowing them to develop projects as EWGs free from the strictures of PUHCA or the QF PURPA limitations.

While sections 211 and 212, as enacted by PURPA, were intended to provide greater access to the transmission grid, the limitations placed on these sections made them unusable in most circumstances.[90] However, as amended by the Energy Policy Act, these sections now give the Commission broader authority to order transmitting utilities to provide wholesale transmission services, upon application, to any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale.

The Energy Policy Act also added section 213 to the FPA. Section 213(a) requires a transmitting utility that does not agree to provide wholesale transmission service in accordance with a good faith request to provide a written explanation of its proposed rates, terms, and conditions and its analysis of any physical or other constraints.[91] Section 213(b) required the Commission to enact a rule requiring transmitting utilities to submit annual information concerning potentially available transmission capacity and known constraints.[92]

5. The Present Competitive Environment

Following the Energy Policy Act, the Commission established rules: (1) for certain generators to obtain EWG status and thus an exemption from PUHCA;[93] and (2) that required transmission information availability. The Commission also pursued a number of initiatives aimed at fostering the development of more competitive bulk power markets, including aggressive implementation of section 211, a new look at undue discrimination under the FPA, easing of market entry for sellers of generation from new facilities, and initiation of a number of industry-wide reforms. As stated by the Commission, in recognition of the Congressional goal in the Energy Policy Act of creating competitive bulk power markets:

> Our goal is to facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa.[94]

a. Use of Sections 211 and 212 to Obtain Transmission Access. The Commission has aggressively implemented sections 211 and 212 of the FPA, as amended by the Energy Policy Act, in order to promote competitive markets.[95] When wheeling requests under sections 211 and 212 have been made, the Commission has required wheeling in almost all of the requests it has processed. To date, the Commission has issued orders requiring wheeling in 9 of the 10 cases it has acted on, including 3 proposed orders and 6 final orders.[96]

As a general matter, section 211 has permitted some inroads to be made by customers in obtaining transmission service from public utilities that historically have declined to provide access to their systems, or have offered service only on a discriminatory basis. Under section 211, the Commission has granted requests for the broader type of service that most utilities historically have refused to provide—network service. Although transmission owners have provided limited amounts of unbundled point-to-point transmission service, third-party customers have not been able to obtain the flexibility of service that transmission owners enjoy.

In *Florida Municipal,* a section 211 case, the Commission ordered ''network,'' rather than the narrower ''point-to-point,'' service.[97] Network service permits the applicant to fully integrate load and resources on an instantaneous basis in a manner similar to the transmission owner's integration of its own load and resources. At the same time, the Commission made the generic finding that the availability of transmission service will enhance competition in the market for power supplies and lead to lower costs for consumers. The Commission explained that as long as the transmitting utility is fully and fairly compensated and there is no unreasonable impairment of reliability, transmission service is in the public interest.[98]

As discussed in more detail above, however, our preliminary conclusion is that section 211 alone is not enough to eliminate undue discrimination. The significant time delays involved in filing an individual service request for bilateral service under section 211 places the customer at a severe disadvantage compared to the transmission owner and can result in discriminatory treatment in the use of the transmission system. It is an inadequate procedural substitute for readily available service under a filed non-discriminatory open access tariff. As the Commission noted in *Hermiston Generating Company,* ''[t]he ability to spend time and resources litigating the rates, terms and conditions of transmission access is not equivalent to an enforceable voluntary offer to provide comparable service under known rates, terms and conditions.''[99]

b. Commission's Comparability Standard. In the Spring of 1994, the Commission began to address the problem of the disparity in transmission service that utilities provided to third parties in comparison to their own uses of the transmission system. In the seminal case in this area, American Electric Power Service Corporation (*AEP*), the company voluntarily proposed a tariff of general applicability that would offer firm, point-to-point

[90] See supra note 67.

[91] See Policy Statement Regarding Good Faith Requests for Transmission Services and Responses by Transmitting Utilities Under Sections 211(a) and 213(a) of the Federal Power Act, as Amended and Added by the Energy Policy Act of 1992, 58 FR 38964 (July 21, 1993), III FERC Stats. & Regs., Regulations Preambles ¶ 30,975 (1993) (Policy Statement Regarding Good Faith Requests for Transmission Services).

[92] See Order No. 558, New Reporting Requirements Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities Under the Energy Policy Act of 1992, and Conforming and Other Changes to Form No. FERC–714, III FERC Stats. & Regs., Regulations Preambles ¶ 30,980, *reh'g denied,* Order No. 558–A, 65 FERC ¶ 61,324 (1993), *regulations modified,* 59 FR 15333 (April 1, 1994), III FERC Stats. & Regs., Regulations Preambles ¶ 30,993.

[93] See Order No. 550, Filing Requirements and Ministerial Procedures for Persons Seeking Exempt Wholesale Generator Status, 58 FR 8897 (February 18, 1993), III FERC Stats. & Regs., Regulations Preambles ¶ 30,964, *order on reh'g,* Order No. 550–A, 58 FR 21250 (April 20, 1993), III FERC Stats. & Regs., Regulations Preambles ¶ 30,969 (1993). As recognized by Congress and the Commission, availability of transmission information is critical in developing competitive markets. See *supra* notes 91 and 92. This opened the ''black box'' of information that previously was available only to transmission owners.

[94] See Stranded Cost NOPR at 32,866; American Electric Power Service Corporation, 67 FERC ¶ 61,168, *clarified,* 67 FERC ¶ 61,317 (1994).

[95] 16 U.S.C.A. 824j–824k (West 1985 and Supp. 1994).

[96] See, e.g., final orders issued in City of Bedford, 68 FERC ¶ 61,003 (1994), *reh'g pending; Florida Municipal Power Agency* v. *Florida Power & Light Company,* 67 FERC ¶ 61,167 (1994), *reh'g pending;* Minnesota Municipal Power Agency, 68 FERC ¶ 61,060 (1994); and Tex-La Electric Cooperative of Texas, 69 FERC ¶ 61,269 (1994); see also *supra* note 168.

[97] See *Florida Municipal Power Agency* v. *Florida Power & Light Company,* 65 FERC ¶ 61,125, *reh'g dismissed,* 65 FERC ¶ 61,372 (1993), *final order,* 67 FERC ¶ 61,167 (1994), *reh'g pending.* The Commission has ''characterized point-to-point service as involving designated points of entry into and exit from the transmitting utility's system, with a designated amount of transfer capability at each point.'' *El Paso Electric Company* v. *Southwestern Public Service Company,* 68 FERC ¶ 61,182 at 61,926 n.9 (1994) (citing Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,768 (1993), *reh'g dismissed,* 68 FERC ¶ 61,399 (1994)). Network service allows more flexibility by allowing a transmission customer to use the entire transmission network to provide generation service for specified resources and specified loads without having to pay multiple charges for each resource-load pairing.

[98] *Florida Municipal,* 67 FERC at 61,477.

[99] 69 FERC ¶ 61,035 at 61,165 (1994), *reh'g pending; see also* Southwest Regional Transmission Association, 69 FERC ¶ 61,100 at 61,398 (1994) (SWRTA).

transmission service for a minimum of one month.[100] The Commission accepted the proposed transmission tariff for filing and suspended its effectiveness for one day, subject to refund.[101] Rehearing requests challenged the Commission's summary approval of the restriction of service to point-to-point as being discriminatory and anticompetitive.[102] The rehearing requests argued that the tariff should be expanded to include network services such as those used by the transmission owner. On rehearing, the Commission announced a new standard for evaluating claims of undue discrimination.

The Commission found that a voluntarily offered, new open access transmission tariff that did not provide for services comparable to those that the transmission owner provided itself was unduly discriminatory and anticompetitive.[103] In reaching that conclusion, the Commission broadened its undue discrimination analysis (which traditionally had focused on the rates, terms, and conditions faced by similarly situated third-party customers) to include a focus on the rates, terms, and conditions of a utility's own uses of the transmission system:

> [A]n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system.[104]

Refocusing the analysis was necessitated by the changing conditions in the electric utility industry, including the emergence of non-traditional suppliers and greater competition in bulk power markets. Because a transmission provider may use its system in different ways (*e.g.*, to integrate load and resources when serving retail native load, to make off-system sales or purchases, or to serve wholesale requirements customers), the Commission set for hearing the factual issues associated with identifying those uses, as well as any potential impediments or consequences to providing comparable services to third parties.[105]

After *AEP*, the Commission applied this comparability standard to a proposed open access transmission tariff that was filed by Kansas City Power & Light Company in support of a proposal to sell generation at market-based rates.[106] The Commission explained that, in light of *AEP*, the utility's proposed open access transmission tariff (which provided only for point-to-point service) did not adequately mitigate its transmission market power so as to justify allowing the requested market-based rates. KCP&L could charge market-based rates for sales only if it modified its proposed transmission tariff to reflect the *AEP* comparability standard.

Since then, the Commission has required comparable service in a variety of contexts, and has set for hearing the factual issues associated with comparable service. For example, the Commission found that market power can be adequately mitigated only if a merged company offers transmission services in accordance with the *AEP* comparability standard.[107] The Commission further held that, even if a merger does not result in an increase in market power, the merger would not be consistent with the public interest under section 203 of the FPA unless the merged company offers comparable transmission services, as defined in *AEP*.[108] The Commission therefore announced a transmission comparability requirement for all new mergers:

> Given the transition of the electric utility industry as a whole, we conclude that, absent other compelling public interest considerations, coordination in the public interest can best be secured only if merging utilities offer comparable transmission services.[109]

In *Heartland Energy Services, Inc.*,[110] the Commission applied its comparability standard to an affiliated electric power marketer seeking blanket authorization to sell electricity at market-based rates. The Commission explained that

> for all future cases involving blanket approval of market-based rates an offer of comparable transmission services will be required before the Commission will be able to find that transmission market power has been adequately mitigated. In the context of an affiliated power marketer, this means that all of its affiliated utilities must have a comparable transmission tariff on file.[111]

The Commission also denied a request by a company affiliated with a transmission-owning utility seeking permission to sell power at market-based rates to a particular customer. The denial was without prejudice to refiling such a request in a new section 205 proceeding, but only after the affiliated transmission-owning utility filed a comparable transmission service tariff.[112] The Commission added that it

> will require comparability in any situation in which a seller seeking market-based rates is affiliated with an owner or controller of transmission facilities.[113]

The Commission has also stated that "it will henceforth apply the transmission comparability standard announced in the *AEP* case to all transmitting utility members of an RTG."[114] The Commission further declared that comparable services must be provided through "open access" tariffs rather than only on a contract-by-contract basis:

> [T]ariffs are essential to the provision of comparable services. Tariffs set out the services that are available and the terms and

[100] 64 FERC ¶ 61,279 (1993), *reh'g granted*, 67 FERC ¶ 61,168, *clarified*, 67 FERC ¶ 61,317 (1994).

[101] The Commission explained that AEP could limit the service it was offering because it was "providing the service voluntarily under a tariff of general applicability." 64 FERC at 62,978.

[102] *AEP*, 67 FERC at 61,489.

[103] With respect to anticompetitive effects, the Commission explained that it has "adhered to the Supreme Court's determination that the Commission's 'important and broad regulatory power * * * carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to sections 202 and 203, and under like directives contained in sections 205, 206 and 207.' *Gulf States Utilities Company* v. *FPC*, 411 U.S. 747, 758–59 (1972)." *Id.* at 61,490 (footnote omitted). The Commission reaffirmed that it would examine how best to fulfill this responsibility, as well as its responsibility to prevent undue discrimination, in light of the changing conditions in the electric utility industry. *Id.*

[104] *Id.* at 61,490.

[105] *Id.* at 61,490–91.

[106] See *Kansas City Power & Light Company*, 67 FERC ¶ 61,183 (1994), *reh'g pending*.

[107] *E.g., CSW, supra* 68 FERC at 61,914.

[108] *Id.*

[109] *Id.* at 915 (footnote omitted).

[110] 68 FERC ¶ 61,223 (1994).

[111] *Id.* at 62,060. In InterCoast Power Marketing Company, 68 FERC ¶ 61,248, *clarified*, 68 FERC ¶ 61,324 (1994), the Commission rejected an affiliated marketer's proposal to sell at market rates without its affiliate utility offering comparable transmission services. The Commission stated that the only way to ensure that InterCoast does not have transmission market power is to require its affiliated public utility to offer comparable transmission services. See also LG&E Power Marketing Inc., 68 FERC ¶ 61,247 at 62,120–21 (1994). The Commission added that this is consistent with encouraging competitive bulk power markets as envisioned by the Energy Policy Act of 1992. *Id.* at 62,132.

[112] See *Hermiston Generating Company*, 69 FERC ¶ 61,035 at 61,164 (1994), *reh'g pending*. The Commission subsequently accepted the rates on a cost basis. See Letter Order dated November 10, 1994.

[113] *Id.* at 61,165.

[114] See *SWRTA*, 69 FERC at 61,397; *see also* PacifiCorp, the California Municipal Utilities Association, and the Independent Energy Producers (on behalf of Western Regional Transmission Association), 69 FERC ¶ 61,099, *order on reh'g*, 69 FERC ¶ 61,352 (1994) (*WRTA*). An RTG is a regional transmission group. It is defined as "a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional (and inter-regional." Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (August 5, 1993), III FERC Stats. & Regs., Regulations Preambles ¶ 30,976 at 30,870 n.4 (RTG Policy Statement).

conditions under which those services will be made available * * *. [In contrast], a negotiation process creates uncertainty and imposes on customers delay and other transaction costs that the transmitting utility members of an RTG do not incur when using the transmission for their own benefit. Moreover, the ability to execute separate transmission agreements with different but similarly situated customers is the ability to unduly discriminate among them. A tariff ensures against such discrimination in the RTG.[115]

Thus, the Commission required the RTGs to amend their bylaws to commit all transmitting utility members to offer comparable transmission services to other RTG members pursuant to a transmission tariff or tariffs.

Most recently, the Commission has set for hearing whether transmission tariffs meet the *AEP* comparability standard in Commonwealth Edison Company,[116] Wisconsin Electric Power Company,[117] and Wisconsin Public Service Corporation.[118] In all three cases, the company agreed in principle to provide comparable service, but issues arose as to what constitutes such service.

c. *Lack of Market Power in New Generation.* In *KCP&L*, discussed in the prior section, the Commission continued to recognize that transmission remains a natural monopoly. However, it found that, in light of the industry and statutory changes that now allow ease of market entry, no wholesale seller of generation has market power in generation from new facilities.[119] In particular, the Commission explained that it had previously noted in *Entergy Services, Inc.* that

there was significant evidence that non-traditional power project developers, including qualifying facilities and independent power projects, are becoming viable competitors in long-run markets.[120]

The Commission further explained that since *Entergy*, Congress had enacted the Energy Policy Act, which had lowered barriers to the entry of new suppliers by creating a new class of power suppliers—EWGs—that are exempt from the provisions of PUHCA.[121] The Commission concluded that, in considering market-based rate proposals for generation sales, it need only focus on market power in transmission, generation market power in short-run markets, and other barriers to entry.[122]

d. *Further Commission Action Addressing a More Competitive Electric Industry.* To address the fact that the electric industry is becoming more competitive, and to remove barriers that might inhibit a more competitive industry, the Commission has initiated a number of additional proceedings: (1) Stranded Cost Notice of Proposed Rulemaking,[123] (2) Transmission Pricing Policy Statement,[124] (3) Pooling Notice of Inquiry,[125] and (4) Regional Transmission Group (RTG) Policy Statement.[126]

In the Stranded Cost NOPR the Commission recognized that the trend toward greater transmission access and the transition to a fully competitive bulk power market could cause some utilities to incur stranded costs as wholesale requirements customers (or retail customers) use their supplier's transmission to purchase power elsewhere. As the Commission noted, a utility may have built facilities or entered into long-term fuel or purchased power supply contracts with the reasonable expectation that its customers would renew their contracts and would pay their share of long-term investments and other incurred costs. If the customer obtains another power supplier, the utility may have stranded costs. If the utility cannot locate an alternative buyer or somehow mitigate the stranded costs, the Commission explained that ''the costs must be recovered from either the departing customer or the remaining customers or borne by the utility's shareholders.'' [127] Accordingly, the Commission proposed to establish provisions concerning the recovery of wholesale and retail stranded costs by public utilities and transmitting utilities.[128]

In the Transmission Pricing Policy Statement, the Commission announced a new policy providing greater flexibility in the pricing of transmission services provided by public utilities and transmitting utilities. The Commission traditionally had allowed only postage-stamp, contract-path pricing.[129] Under the new policy, it will permit a variety of proposals, including distance sensitive and flow-based pricing,[130] which may be more suitable for competitive wholesale power markets. The Commission explained that this ''[g]reater pricing flexibility is appropriate in light of the significant competitive changes occurring in wholesale generation markets, and in light of our expanded wheeling authority under the Energy Policy Act of 1992.'' [131] However, the Commission explained that any new transmission pricing proposal must meet the Commission's AEP comparability standard. The Commission further explained that comparability of service applies to price as well as to terms and conditions.[132]

The Commission issued the Pooling Notice of Inquiry to receive comments on traditional power pools and on alternative power pooling institutions that are being explored in today's more competitive environment. The Commission expressed concern that

[g]iven the ongoing changes in the competitive environment of the electric utility industry—in particular, the potential for substantially increased access to transmission—we must consider whether we

---

[115] *SWRTA*, 69 FERC at 61,398.

[116] 70 FERC ¶ 61,204 (1995).

[117] 70 FERC ¶ 61,074 (1995).

[118] 70 FERC ¶ 61,075 (1995).

[119] KCP&L, 67 FERC ¶ 61,183 (1994).

[120] *Id.* at 61,557 (citing Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,756 and nn.63 and 65 (*Entergy*)).

[121] *Id.* The Commission added that ''after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets.'' *Id.*

[122] *Id.* In *KCP&L*, the Commission declined to dismiss the possibility of market power in generation associated with sales out of *existing* capacity. As noted, however, we here seek comments on whether, and if so under what conditions, to drop the generation dominance standard in short-run markets, *i.e.*, for sales from existing capacity.

[123] See supra note 5.

[124] See Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 59 FR 55031 (November 3, 1994), III FERC Stats. & Regs., Regulations Preambles ¶ 31,005 (Transmission Pricing Policy Statement).

[125] See Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, 59 FR 54851 (October 26, 1994), IV FERC Stats. & Regs., Notices ¶ 35,529 (1995) (Pooling Notice of Inquiry).

[126] See Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (August 5, 1993), III FERC Stats. & Regs., Regulations Preambles ¶ 30,976 (RTG Policy Statement).

[127] Stranded Cost NOPR at 32,864.

[128] The Commission herein is making preliminary findings on stranded costs and issuing a supplemental Stranded Cost NOPR, seeking comments on the impact of our proposed open access NOPR on stranded costs.

[129] Most transmission contracts set a single price for energy flow over a utility's transmission system. This single-price policy is called ''postage stamp'' pricing because the rate does not depend on how far the power moves within a company's transmission system. If power flows through several companies, traditional industry practice is to specify that power flows along a ''contract path'' consisting of the transmission-owning utilities between the ultimate receipt and delivery points. See *infra* discussion of Indiana Michigan Power Company, 64 FERC ¶ 61,184.

[130] Unlike with postage stamp pricing, with distance-sensitive pricing the cost of moving power through a company depends on how far the power moves within the company. In contrast to contract path pricing, flow-based pricing establishes a price based on the costs of the various parallel paths actually used when the power flows. Because flow-based pricing can account for all parallel paths used by the transaction, all transmission owners with facilities on any of the parallel paths would be compensated for the transaction.

[131] Transmission Pricing Policy Statement at 31,136.

[132] *Id.* at 31,142.

are appropriately balancing our dual objectives of promoting coordination and competition.[133]

Accordingly, the Commission explained that it wished to look at alternative power pooling institutions and to re-examine the role of more traditional power pools in today's environment of increased competition. In particular the Commission expressed its intent to ensure that its policies ''are consistent with the development of a competitive bulk power market.'' [134]

In the RTG Policy Statement, the Commission announced a policy encouraging the development of RTGs. The Commission explained that a primary purpose of RTGs is to facilitate transmission access for potential users and voluntarily resolve disputes over such service. The Commission has recently conditionally approved the formation of two RTGs.[135] One of the conditions is that each RTG member must offer comparable transmission services by tariff to other RTG members.

In addition to the Commission's actions, a number of states have initiated proceedings concerning retail wheeling or proposed legislation for retail wheeling, that is, for ultimate consumers to choose their supplier of power.[136]

D. Need for Reform

The many changes discussed above have converged to create a situation in which new generating capacity can be built and operated at prices substantially lower than many utilities' embedded costs of generation. As discussed above, new generation facilities can produce power on the grid at a cost of 3 to 5 cents per kWh, yet the costs for large plants constructed and installed over the last decade were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants. Non-traditional generators are taking advantage of this opportunity to compete. Indeed, the non-traditional generators' share of total U.S. electricity generation increased from 4 percent in 1985 to 10 percent in 1993.[137] Much of this increased share of generation is the result of competitive bidding for new generation resources that has occurred in 37 states. Since 1984, almost 4,000 projects, representing over 400,000 MW, have been offered in response to requests. Over 350 projects have been selected to supply 20,000 MW, and, of these, 126 are now online producing almost 7,800 MW of power.[138] In addition, the cost of utility-generated electricity differs widely across the major regions of the United States. Average utility rates range from 3 to 5 cents in the Northwest to 9 to 11 cents in California.[139] Electricity consumers are demanding access to lower cost supplies available in other regions of the United States, and access to the newer, lower cost generation resources. It is also important that the non-traditional generators of cheaper power be able to gain access to the transmission grid on a non-discriminatory open access basis.

The Commission's goal is to ensure that customers have the benefits of competitively priced generation. However, we must do so without abandoning our traditional obligation to ensure that utilities have a fair opportunity to recover prudently incurred costs and that they maintain power supply reliability. As well, the benefits of competition should not come at the expense of other customers. The Commission believes that requiring utilities to provide non-discriminatory open access transmission tariffs, while simultaneously resolving the extremely difficult issue of recovery of transition costs (discussed infra), is the key to reconciling these competing demands.

Non-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition.[140] Transmitting utilities own the transportation system over which bulk power competition occurs and transmission service continues to be a natural monopoly. Denials of access (whether they are blatant or subtle), and the potential for future denials of access, require the Commission to revisit and reform its regulation of transmission in interstate commerce. Such action is required by the FPA's mandate that the Commission remedy undue discrimination.

1. Market Power

Unlike new generating capacity (*see* prior discussion of *KCP&L*), transmission remains and is expected to remain a natural monopoly. The Commission has addressed the natural monopoly character of transmission in the major cases summarized above and in the Commission's recent Transmission Pricing Policy Statement. The monopoly characteristic exists in part because entry into the transmission market is restricted or difficult.[141] In addition, as unit costs are less for larger lines and networks, transmission facilities still exhibit scale economies. From an economic, environmental, and aesthetic viewpoint, it is often better for a single owner (or group of owners) to build a single large transmission line rather than for many transmission owners to build smaller parallel lines on a non-coordinated basis.

Further, effective competition among owners of parallel transmission lines is unlikely, and often impossible, with existing practices and technology. For example, on an alternating current (AC) electric system, electricity flows on parallel paths based on the impedance of each path. With two electric systems providing parallel contract paths, a share of the actual power flows would occur on each system according to the physical characteristics of the system. Thus, each of the two transmission service providers would have the incentive to underbid the other because the winner would receive all of the transmission revenues, but only incur a fraction of the costs. The loser, on the other hand, would incur the remaining costs, but would receive no revenues.

In today's electric industry, which is dominated by vertically integrated utilities, an owner or controller of transmission service can exclude generation competitors from the market, thereby favoring the transmission

[133] Pooling Notice of Inquiry at 35,715.

[134] *Id.* at 35,714.

[135] *See WRTA* and *SWRTA, supra.*

[136] The Energy Information Administration recently indicated that at least nine states—California, Connecticut, Illinois, Michigan, Nevada, Ohio, Texas, Utah, and Vermont have proposals or legislation for retail wheeling. EIA, Performance Issues for a Changing Electricity Power Industry, January 1995 19–22. Most prominent among the recent state proposals are the California Public Utility Commission's ''Blue Book'' proposal (Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, R. 94–04–031; Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, I. 94–04–032) and the Michigan Public Service Commission's proposal (Interim Order on Experimental Retail Wheeling Program, Case No. U–10143/U–10176 (April 11, 1994)).

[137] Energy Information Administration, Performance Issues for a Changing Electric Power Industry (January 1995) 10 and (Figure 5).

[138] Current Competition, November 1994, Vol. 5, No. 8, at 8.

[139] See map attached as Appendix A. This Appendix will not appear in the **Federal Register**.

[140] As discussed above, only a minimal number of public utilities have any form of an ''open access'' tariff on file with the Commission and no public utility has on file a non-discriminatory open access tariff as defined by this rule.

[141] An example of this is that, except in the limited case of licensed hydroelectric projects under Part I of the FPA, there is no Federal right of eminent domain available to assist in acquiring rights of way for new transmission lines. In addition, the regulatory requirements to build a transmission line vary from state to state. In all states, siting new transmission lines is getting harder.

owner's own generation. This can occur through outright denial of transmission access, or, as is more likely, through access that is discriminatory as to rates, terms or conditions of service.[142] Thus, in the absence of non-discriminatory open access tariffs, the development of fully competitive bulk power markets cannot occur, and consumers will be deprived of the benefits that would be expected from such a competitive market.

2. Discriminatory Access

Some transmission-owning utilities have voluntarily begun to offer unbundled transmission tariff services to third-party suppliers and purchasers of wholesale power, though none have done so to the extent proposed by this proposed rule.[143] However, because utilities are naturally profit maximizers and monopoly suppliers to their native load, the vast majority of transmission-owning utilities have not agreed to give up their market power voluntarily. Transmission-owning utilities have an incentive to deny access either by not filing any open access tariff or by filing a tariff that offers services inferior to those used by the transmission owner. This is particularly true for those utilities that emerged from the recent decades of technological and legal changes as high-cost generation companies. Open access transmission places their existing generation at risk because their wholesale customers may seek alternative lower price suppliers. It is in their self-interest to maintain and use market power to retain (or expand) market share for their existing generation facilities, at least until they can get their generation costs in line with current market prices. Because generating units are usually depreciated over a 30- to 50-year physical life, many high cost companies may attempt to exercise transmission market power for decades to preserve the value of past generation investments.

Unless all public utilities are required to provide non-discriminatory open access transmission, the ability to achieve full wholesale power competition, and resulting consumer benefits, will be jeopardized. If utilities are allowed to discriminate in favor of their own generation resources at the expense of providing access to others' lower cost generation resources by not providing open access on fair terms, the transmission grid will be a patchwork of open access transmission systems, systems with bilaterally negotiated arrangements, and systems with transmission ordered under section 211. Under such a patchwork of transmission systems, sellers will not have access to transmission on an equal basis, and some sellers will benefit at the expense of others. The ultimate loser in such a regime is the consumer.

A patchwork of transmission systems will also result in inefficiencies across the Nation's transmission grids. Because of the physical properties of the transmission system, electric power moves over parallel transmission lines from generator to load, without regard to whether a line is part of a system providing open access or not.[144] However, today the industry develops transmission contracts as if power flowed along one series of lines belonging to specific owners, which is called the ''contract path.'' Thus, transmission users will search for contract paths through open access systems to take advantage of the non-discriminatory open access tariffs. Because open access transmission tariffs include an obligation to expand when necessary to accommodate third-party requirements for service, transmitting companies offering open access services across their systems could end up constructing a disproportionate share of new transmission facilities.

Expansion cannot be efficient under such a patchwork of open access transmission systems. Not only would this misallocate cost burdens to open access companies, but it is unlikely that the optimal transmission development will always be within their service territories. Expansion on closed systems, instead of open systems, may in some cases be the more efficient way to relieve constraints. Thus, a patchwork of open access systems will not result in the least cost expansion of the Nation's transmission grids. In addition, states with open access utilities may refuse to site new lines if their closed access neighbors are not doing their share.[145]

A discriminatory, patchwork system also works against pricing parallel power flows on a sensible regional basis. The formation of effective regional transmission groups, which the Commission strongly encourages, would be fostered if all utilities in a region offered non-discriminatory open access.[146] In fact, optimal cooperative regional action would involve all transmission systems in the region offering non-discriminatory open access to all wholesale customers.

A transmission-owning utility may deny access to third parties not only to avoid losing its own generation sales, but also to maintain other trading gains. For example, a company can buy low cost power for its own use from a neighbor at a low price if other buyers cannot reach that neighbor to bid up the price. Furthermore, if it does not need the energy, it can market that power by buying low and selling high.

In the past, transmission-owning utilities have discriminated against others seeking transmission access. Transmission-owning utilities have denied access by outright refusals to deal. While such actions tend to be rare, likely because transmission owners fear they may trigger antitrust action,[147] they have occurred.[148] More often, however, discrimination is likely to be manifested more subtly and indirectly.[149] One such

[142] See, *e.g.*, David W. Penn, A Municipal Perspective on Electric Transmission Access Questions, Pub. Util. Fort. 18–19 (Feb. 6, 1986).

[143] The majority have offered only point-to-point services. However, a few utilities have sought to comply with the non-discrimination (comparability) standard announced in *AEP*. For example, Kansas City Power & Light Company (KCP&L) and Louisville Gas & Electric Company (LG&E) recently filed settlements to this effect. KCP&L, Docket No. ER94–1045 (settlement filed February 14, 1995) and *LG&E*, Docket No. ER94–1380 (settlement filed February 10, 1995).

[144] In Indiana Michigan Power Company, 64 FERC ¶ 61,184 (1993), the Commission explained loop flows and parallel power flows:

In general, utilities transact with one another based on a contract path concept. For pricing purposes, parties assume that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. However, in reality power flows are rarely confined to a designated contract path. Rather, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being transmitted from one utility to another to travel along multiple parallel paths and divide itself among those paths along the lines of least resistance. This parallel path flow is sometimes called ''loop flow.''

Id. at 62,545.

[145] The Commission partially addressed this concern by allowing reciprocity provisions in open access transmission tariffs. See, *e.g.*, Southwestern Electric Power Company and Public Service Company of Oklahoma, 65 FERC ¶ 61,212 at 61,981–82 (1993), *order on reh'g*, 66 FERC ¶ 61,099 (1994).

[146] While the Commission has conditioned its approval of RTGs to achieve this same result, the formation of RTGs is voluntary. By contrast, compliance with the final rules adopted in this proceeding will be required.

[147] See, *e.g.*, Penn, *supra* note 142, at 18.

[148] Otter Tail Power Company refused to wheel power for the village of Elbow Lake. The Supreme Court ultimately ruled against Otter Tail on antitrust grounds. Otter Tail Power Company, 410 U.S. 366 (1974). The Commission has also found that Utah Power & Light Company consistently refused to permit the wheeling of low-cost power across its system in order to use its strategically located bottleneck transmission system to extract monopoly prices. Utah Power & Light Company, *supra*, 45 FERC at 61,287 and n.137 (1988).

[149] See, *e.g.*, Penn, *supra* note 142, at 18–19 (discussion of methods used to deny access). Penn also noted in his 1986 article that the American Public Power Association had conducted a survey of its members in which about 25% indicated a

way would be for transmission owners to adopt a negotiating strategy that involves a sequence of informational and other requirements over a protracted period of time. By the time all of the requirements are finally satisfied, the window for the customer's trade opportunity has closed.[150] Another way of frustrating access is to substantially change the terms of negotiated agreements through protracted delay, including filings with regulatory agencies.[151]

Another way for transmission-owning utilities to frustrate access and competition is to allow access, but only on non-comparable or unsupportable terms and conditions that are inferior to the conditions under which the transmission owners themselves use or could use the transmission grid or on terms and conditions that have no operational or financial basis. Discrimination can be exercised this way in the following areas:

(1) *Network Service.* Network service allows a transmission customer to distribute a given amount of transmission usage between specified resources and specified loads without having to pay multiple charges for each resource-load pairing. Transmission owners can refuse to provide service on these terms and instead insist on charges that are a function of the number of resource load pairings.[152] This can dramatically increase the cost of such service. Such treatment does not reflect the way transmission owners' costs are allocated to their own native load customers.

(2) *Pricing.* Transmission service can be made unattractive to third-party customers by pricing such service on a basis that is different from that used by the transmission owner and that results in higher rates. One example would be charging third-party customers distance-sensitive rates, while pricing all similar transmission bundled with power services on a postage stamp basis.[153]

(3) *Service Priority.* The priority of transmission service is a critical service factor. The transmission provider could disadvantage third-party transmission customers by making firm transmission service to them subordinate to the transmission utility's native load service.[154]

(4) *Scheduling and Balancing Provisions.* A transmission owner could hold transmission customers to unnecessarily long lead times to change power schedules. In some cases, scheduling could be required as much as a month ahead of time.[155] This precludes transmission customers from using their service for short-term trading. Transmitting utilities may also insist that customers keep strict adherence to scheduling and balancing provisions by requiring them to get back on schedule quickly or face stiff penalties.[156] One example of a stiff penalty for failure to schedule sufficient power would be to assess shortfalls based on a partial requirements rate with an 11-month ratchet.[157] In contrast, transmitting utilities may have access to less costly balancing alternatives, such as substituting resources without notice or borrowing capacity from neighboring utilities and settling the imbalance by returning energy in-kind within a much longer time period than allowed to customers.[158]

(5) *Use of Firm Transmission Capacity.* Transmission owners can unnecessarily restrict the firm transmission capacity made available to transmission customers. One way to restrict service would be to prohibit the customer from reassigning such capacity when it is not needed.[159] This restricts the customer's ability to manage the risk of long-term capacity purchases and to compete as a seller in the transmission service market. Another example would be that the transmission owner could restrict a customer's use of transmission capacity by allowing sales only from the customer's generating resources that are temporarily in excess of actual load needs.[160] Transmission owners do not face these restrictions in their own use of transmission capacity.

(6) *Ancillary Services.* A transmitting utility may offer to a transmission customer ancillary services (e.g., scheduling) that are inferior to the services it provides for itself. Transmission owners may be free to choose whether to supply some of these services to themselves or contract for them if available more cheaply elsewhere.[161] Third-party transmission customers do not always have this option on a comparable basis.

(7) *Creditworthiness and Security Deposits.* Customers are sometimes required to make onerous deposits in order to obtain service.[162]

(8) *Reciprocity Double Payments.* Transmission agreements often require reciprocity. Non-transmission owners could be required to contract with, and pay, third-party transmitting utilities to provide the required reciprocal service.[163] Transmission owners do not face such obstacles in using their own systems.

Finally, an additional way for transmission-owning utilities to frustrate access and competition is by granting each other superior rights and lower rates—compared to those available to non-transmission owning customers—in pools, interconnection agreements, and other protocols.[164] For example, pool-wide transmission service can be made available to members at rates less than those that each member would separately propose under traditional rate methods. This could disadvantage non-transmission owners if pool membership is restricted or if it requires excessive or vaguely stated transmission contributions that could be difficult to meet.[165]

Section 211 is not always a sufficient remedy for this discriminatory behavior. Third parties may seek non-discriminatory transmission under section 211, but they will not be able to compete if the sale or purchase

---

problem in securing transmission in effecting coordination services and about an equal amount had reported being denied transmission access in the recent past. *Id.* at 18. See also Pacific Gas & Electric Company, 51 FPC 1030, 1031–32, *reh'g denied,* 51 FPC 1543 (1974) (parties alleged that public utility proposed "a wholesale rate so high that its wholesale customers would be unable to compete with PG&E for large industrial retail loads" and entered into restrictive and anticompetitive contracts that strengthened public utility's monopoly).

[150] Members of the Coalition for a Competitive Electricity Market alleged that they have encountered this strategy. Coalition Petition at 13, n.19.

[151] An example of this tactic is evident in the history of Pacific Gas and Electric Company's (PG&E) attempt to avoid its commitments made to the California owners of the California-Oregon Transmission Project (COTP). The owners had originally planned the COTP to have its southern terminus at the Midway station with Southern California Edison. PG&E convinced them to terminate the project instead at PG&E's Tesla station and indicated that PG&E would provide transmission service the rest of the way south to Midway. PG&E promised this service in 1989 (in what came to be known as the South of Tesla Principles). PG&E spent the next four years filing substitute provisions for what it had promised in the Principles. See Pacific Gas and Electric Company, 65 FERC ¶ 61,312 at 62,428–30 and n.22, *remanded on other grounds,* Pacific Gas & Electric Company v. FERC, No. 94–70037 (9th Cir. June 23, 1994) (unpublished opinion), *order on remand,* 69 FERC ¶ 61,006 (1994).

[152] See Pacific Gas and Electric Company, 52 FERC ¶ 61,347 at 62,375–76 (1990) (proposal to charge a base demand and a flexibility adder for an integrating transmission service). PG&E eventually withdrew the proposal. 56 FERC ¶ 61,373 at 62,429 (1991); see also Florida Municipal Power Agency v. Florida Power & Light Company, 65 FERC ¶ 61,125 (1993) (Federal Municipal Power Agency requested a section 211 order directing network service); Tex-La Electric Cooperative of Texas, 67 FERC ¶ 61,019 at 61,057 (1994) (Tex-La requested a section 211 order directing network service).

[153] See notes 129 and 130, *supra*; see also *Tex-La Electric Cooperative of Texas,* 69 FERC ¶ 61,269 at 62,034–35 (1994), in which the Commission found this practice to be unduly discriminatory.

[154] See AEP, 64 FERC at 62,971–72.

[155] Id.

[156] See Coalition Petition at 20–21.

[157] See Borough of Zelienople, 70 FERC ¶ 61,073 at 61,184 (1995) (load exceeding schedule by 1 MW would be filled at a partial requirements rate using a 60% demand ratchet for 11 months, i.e., 1 MW times 60% times $9.30 per kW times 11, for a total of $61,380).

[158] See Coalition Petition at 20–21.

[159] See, *e.g.*, Pacific Gas and Electric Company, 53 FERC ¶ 61,145 at 61,505 (1990) (utility proposed a reassignment prohibition on the use of Reserve Transmission Service available to the Sacramento Municipal Utility District under a proposed Interconnection Agreement).

[160] *Id.* at 61,504–05 (utility proposed an export restriction on the use of Reserve Transmission Service available to the Sacramento Municipal Utility District under a proposed Interconnection Agreement).

[161] See Coalition Petition at 28–29 and 32.

[162] For example, it is reported that one customer was told that a $13 million line of credit would be required to ensure creditworthiness for a request of only one MW of transmission capacity for a coordination trade. See Coalition Petition at 30.

[163] See Coalition Petition at 25; see also AES Power, Inc., 69 FERC ¶ 61,345 at 62,295 and 62,301 (1994) (*AES*).

[164] See Coalition Petition at 13–14.

[165] See Mid-Continent Area Power Pool, 69 FERC ¶ 61,347 at 62,308 (1994).

opportunity is gone before a final order can be obtained under section 211. This could be the case in many situations because of the procedural requirements of sections 211 and 212.[166] Indeed, to date, the Commission has received eighteen section 211 transmission requests,[167–168] which it has tried to process expeditiously within the procedural constraints contained in sections 211 and 212. As to the seven requests that have received a final order, the average elapsed time from date of filing to the date of a final order was 9 months. The remaining ten requests have been pending, on average, more than 6 months.

The following sets forth the status of the section 211 cases filed with the Commission:

Docket No.	Date of application	Status	Months pending
TX93–1 ..	01/19/93	Final Order-7/29/93.	6
TX93–2 ..	06/18/93	Final Order-7/1/94.	12
TX93–3 ..	06/30/93	Withdrew-9/10/93.	2
TX93–4 ..	07/02/93	Final Order-5/11/94.	10
TX94–1 ..	10/21/93	Final Order-7/6/94.	9
TX94–2 ..	11/04/93	Pending [a]	16
TX94–3 ..	11/09/93	Final Order-7/13/94.	8
TX94–4 ..	12/15/93	Final Order-12/1/94.	11
TX94–5 ..	04/15/94	Final Order-3/23/95.	11
TX94–6 ..	07/05/94	Pending	8
TX94–7 ..	07/15/94	Pending [a]	8
TX94–8 ..	08/05/94	Pending	7
TX94–9 ..	09/09/94	Pending [a]	6
TX94–10	09/16/94	Pending	6
TX95–1 ..	10/11/94	Pending	5
TX95–2 ..	10/17/94	Pending	5
TX95–3 ..	01/19/95	Pending	2
TX95–4 ..	01/24/95	Pending	2

[a] A proposed order has been issued.

As the wholesale power markets become more competitive, delayed access becomes a matter of increasing concern. Not only have long-term purchases from non-traditional generators become more important, but short-term firm and non-firm power sales and purchases create significant profit or cost-saving opportunities for utilities, marketers, and their customers. As a result, market participants are exploring various ways to reduce their costs through trading. These include poolcos, changes to existing pools, short-term trading systems, and futures contracts.[169] We do not see how such options will work unless all parties have non-discriminatory transmission access rights and hour-to-hour access without having to go through a regulatory proceeding for each trade.

In today's emerging competitive wholesale power markets, the practices of some transmission-owning utilities are unduly discriminatory and anticompetitive. These practices produce market distortions today, undermine the goal of the Energy Policy Act to create competitive bulk power markets, and will continue if this Commission does not take action. Most important, they can harm consumers by denying them the benefits of competitively priced power. We seek additional specific examples of such practices.

3. Analogies to the Natural Gas Industry

The electric industry today is analogous in many ways to the natural gas industry before the Commission issued Order Nos. 436 and 636.[170] Then, natural gas pipelines were primarily merchants offering a bundled sales service, which provided gas to customers at the city-gate from the pipelines' own system supplies. In addition, pipelines moved a relatively small amount of third-party gas under a separate transportation service. To meet their sales service obligations, pipelines purchased most of their system supply from third-party producers under long-term contracts. In the early 1980s, due to changing market conditions, the prices under many of these contracts ended up being higher than those available in the then evolving spot market. Because of the long-term contracts and the resulting higher cost gas, system supply gas tended to be more costly than gas that the customers could buy in the competitive spot market. At the same time, the transportation service bundled with a pipeline's sales service was usually superior to the transportation service third parties could obtain. Essentially, the pipeline would provide itself service that had much greater flexibility and often promised greater reliability than that available to third-party shippers. Pipelines had a considerable incentive to maintain this difference in transportation service quality to make their own, more expensive gas more attractive.

A similar situation exists today in the electric industry. Traditional public utilities deliver bundled service—generation and transmission—to most of their wholesale customers. They have monopoly control over transmission facilities and thus control access to their customers. The lack of non-discriminatory access to transmission services raises the same general concerns that were prevalent in the gas industry. Accordingly, unless similar regulatory measures are undertaken, the Commission expects the same type of discriminatory and anticompetitive behavior will continue in the electric industry as was present in the gas industry, because denying non-discriminatory access will continue to be in the economic self-interest of transmission monopolists, absent regulatory changes.[171]

In its regulation of interstate pipelines under the Natural Gas Act (NGA) the Commission initially addressed the problem of undue discrimination in Order No. 436, finding natural gas pipeline practices to be unduly

[166] For example, an applicant must make a request for transmission service to the transmitting utility at least 60 days before filing an application with the Commission for an order to provide transmission. The Commission must first issue a proposed order and allow the parties a reasonable time to negotiate agreeable terms and conditions before it can issue a final order. Moreover, a final order faces possible rehearing and a court appeal.

[167–168] One request was withdrawn.

[169] We note that NEPOOL and MAPP are currently exploring ways to modify their pool structures to accommodate competitive power markets. As noted in the Pooling Notice of Inquiry, *supra*, the poolco concept basically involves an independent entity that would control the operation of all transmission facilities and some or all generating facilities in a region. It would be open and would provide transmission service to all generators. Thus, the poolco would create a spot market for power in the region.

[170] Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Regulations Preambles ¶ 30,665 (1985); Order 636, Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 57 FR 13267 (April 16, 1992), III FERC Stats. & Regs., Regulations Preambles ¶ 30,939 (Order No. 636), *appeal pending.*

[171] See *AGD, supra,* 824 F.2d at 1008 (''Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.''). The ongoing discriminatory behavior by owners or controllers of transmission in the electric industry is detailed *supra.*

discriminatory under the NGA [172] and effectuating ''open access'' transportation. The Commission in that order sought to make transportation available to third parties on a non-discriminatory basis. The Commission provided that, if a pipeline held itself out as a transporter of gas for others, it must provide that service to all shippers without discrimination. At the same time, the Commission allowed pipelines and their customers to retain the traditional bundled sales and transportation services under existing certificate authority.

As a result of Order No. 436, pipelines became primarily transporters of natural gas. However, in Order No. 636, the Commission noted that pipelines were still providing, albeit at a reduced level, a bundled, city gate, sales service in competition with third-party sales and transportation, and concluded that the competition was not occurring on an equal basis. The Commission also noted that pipelines' natural gas sales prices exceeded those of their competitors, much as electric utilities' embedded costs can exceed the cost of new generating capacity and excess generating capacity of others. In this regard, the Commission determined that the transportation service bundled with pipelines' sales service was superior to that made available to third parties and that pipelines and unregulated competitors were not selling the same product.[173] Accordingly, in Order No. 636, the Commission found this behavior anticompetitive and required pipelines to ''unbundle'' their sales services from their transportation services and to provide open access transportation service that is equal in quality for all gas supplies whether purchased from the pipeline or some other supplier.[174]

Our experience in the gas area influences our decision that, at a minimum, functional unbundling of wholesale services is necessary in order to obtain non-discriminatory open access and to avoid anticompetitive behavior in wholesale electricity markets.

[172] In this regard, sections 4 and 5 of the NGA are virtually identical to sections 205 and 206 of the FPA.

[173] Order No. 636 at 30,402. The Commission explained that pipelines were selling a regulated bundled sales and transportation service, but that their competitors were generally selling only the gas commodity. The Commission also recognized that pipelines were at a competitive disadvantage due to their certificate and contractual obligations to their firm sales customers. *Id.* at 30,403.

[174] Order No. 636 at 30,393–94.

4. Coordination Rates

In finding a need for non-discriminatory open access transmission, the Commission has considered the structure of the coordination market, *i.e.*, the market for wholesale sales to a public utility's non-requirements customers. Utilities now engage in coordination trades primarily under rates no lower than the seller's variable cost and no higher than that variable cost plus 100% contribution to the fixed costs of the production unit used to price energy and the relevant transmission facilities. This rate flexibility allows the buyer and seller to negotiate a price reflecting the market at the time of the sale, including the number of buyers and sellers, the relative incremental and decremental variable costs, and the amount of savings attainable by transacting. Thus, while the seller's ceiling rate reflects some measure of fixed and variable costs, the actual transaction price is set, to a certain extent, by the marketplace. This marketplace, however, may be skewed by the general lack of transmission access, and the resulting price may be considerably above prices in a fully competitive market.

Some utilities transact under a split-savings rate that generally sets the price halfway between the seller's incremental variable cost and the buyer's decremental variable cost. Here again, price is a function of the alternatives reachable through the transmission grid at the time of the transaction. This rate form is primarily used today to distribute the savings derived from the central dispatch of power pools on an after-the-fact basis.

The Commission believes that unless the participants in coordination markets mitigate their transmission market power, market-driven prices for coordination trades may no longer be just and reasonable. Thus, our preliminary conclusion is that current coordination pricing is no longer justified in the absence of a tariff offer of non-discriminatory open access transmission services by the seller (owning or controlling transmission) in a coordination transaction.[175] The Commission's past practice of allowing such pricing for coordination trades appears to be inconsistent with emerging competitive markets unless those who benefit from such trading offer access to other, lower-priced trading opportunities. We seek comments on this issue.

[175] As discussed *infra*, sellers must also meet the Commission's other requirements to obtain market-based rates.

E. The Proposed Regulations

The goals of the proposed regulations are two-fold: (1) To facilitate the development of competitive wholesale bulk power markets by ensuring that wholesale purchasers of electric energy and wholesale sellers of electricity can reach each other by eliminating anticompetitive practices and undue discrimination in transmission services; and (2) to address the transition costs associated with the development of competitive wholesale markets. This section addresses the elimination of undue discrimination. Transition costs are addressed below in Section F.

Non-discriminatory open access transmission is critical to the ability of sellers to compete on a fair basis and the ability of purchasers to reach the lowest priced generation options. Thus far, the Commission has developed an open access comparability requirement on a case-by-case basis. We have directed our administrative law judges, to whom the various cases have been referred, to examine the factual circumstances surrounding a utility's use of its own system *vis-a-vis* the type of service provided to third parties. Nonetheless, it has now become evident to us that it is necessary for the Commission to define the parameters of a non-discriminatory open access tariff much more precisely.

Until now, we have been applying the new standard of what constitutes undue discrimination only to new voluntary tariff filings. We now no longer believe it is appropriate to apply this standard so narrowly; therefore, we are proposing to require all public utilities to offer non-discriminatory open access services in accord with the proposed rule and the attached tariffs. This broad application is consistent with our determination that undue discrimination by jurisdictional public utilities must be prevented or remedied. It is also consistent with our desire to bring further efficiencies to the provision of electric service by encouraging competitive bulk power markets.

1. Non-discriminatory Open Access Tariff Requirement

Transmission owners can discriminate by restricting access to, or restricting expansion of, transmission facilities, or by restricting access to the ancillary services that control the generation resources on the transmission grid.[176] To ensure that all

[176] Examples of ancillary services (which include control area services) are: Scheduling service between control areas, and various services that facilitate power movements within control areas,

Continued

participants in wholesale electricity markets have non-discriminatory open access to the transmission network, transmission owners must offer non-discriminatory open access transmission and ancillary services to wholesale sellers and purchasers of electric energy in interstate commerce.[177] This will require tariffs that offer point-to-point and network transmission services, including ancillary services. All of these services must be non-discriminatory as to price as well as to non-price terms and conditions. Services must be available to any entity that could obtain transmission services under section 211.

In our *AEP* rehearing order and in several subsequent cases,[178] we set for hearing the following issues:

1. The different uses that a transmission owner makes of its transmission system and whether there are any operational differences between any particular use that the owner makes of the system and the use third parties might need, and in particular, the degree of flexibility the transmission owner accords itself in using its transmission system for different purposes.
2. Any potential impediments or consequences to providing a particular service to third-party transmission customers which is the same or comparable to service that the transmission owner provides itself.
3. The costs that the transmission owner incurs in providing transmission associated with its use of the system, and whether the costs to provide such service or comparable service to third parties would be different.

Based on what we have learned in the past year, the Commission proposes to address these issues generically. Concurrently with this order, the Commission is issuing a separate order on how a final rule would apply to pending cases.[179] We believe that the parties and the administrative law judges in the individual pending proceedings should continue their efforts, but in doing so should take into account the principles announced in this proposed rule. This will permit any fine tuning of the broader principles announced here and set forth in the *pro forma* tariffs that may be necessary to recognize the individual circumstances of particular systems.

With regard to the first issue, the Commission believes that all utilities use their own systems in two basic ways: to provide themselves point-to-point transmission service that supports coordination sales, and to provide themselves network transmission service that supports the economic dispatch of their own generation units and purchased power resources (integrating their resources to meet their internal loads).[180] This network transmission service is bundled as part of retail service and as part of wholesale requirements service, and is the fundamental support of a utility's dispatch that underlies its trading in the wholesale coordination market.[181]

The Commission has preliminarily concluded that third parties may need one or both of these basic uses in order to obtain competitively priced generation or to have the opportunity to be competitive sellers of power. The Commission therefore proposes that all public utilities must offer both firm and non-firm point-to-point transmission service and firm network transmission service on a non-discriminatory open access basis in accord with the proposed rule and the attached tariffs. The Commission believes that a utility's tariff must offer to provide any point-to-point transmission service and network transmission service that customers need, even though the utility may not provide itself the specific service requested. For example, a utility may not provide itself ''wheeling-through'' service,[182] which is a specific form of point-to-point service. However, because ''wheeling-through'' service is merely a subset of basic point-to-point service, which the utility does provide to itself, the Commission will require a utility to provide such service.[183] Similarly, a utility may contend that it does not provide non-firm point-to-point service to itself because all of its transmission investment results in firm entitlements. Nonetheless, the utility provides itself with the functional equivalent of non-firm service when it uses, subject to curtailment or interruption, capacity that is temporarily unused by other firm reservation holders. Therefore, it must offer non-firm point-to-point service.

We will not allow transmission providers to define terms or specify transmission uses to erect barriers to fair and equal competition in power markets, or to engage in undue discrimination.

On the second issue set for hearing in *AEP, et al.* (potential impediments to providing a particular service), we believe there are none, except for impediments to siting. However, any impediments to siting are the same whether the utility is providing service to itself or to a third party.

On the third issue set for hearing *AEP, et al.* (the costs of providing comparable service), we believe there is no difference in the costs incurred by a transmission provider in providing transmission to itself or to a third party. Thus, the transmission owner must charge itself and third parties the same rates for the use of its system.

All electricity trade is supported and facilitated in one way or another by ancillary services, and transmission services may be comprised of many different combinations of ancillary services. Therefore, the Commission will require that such ancillary services be offered separately through open access tariffs. These are discussed in detail *infra.*

Public utilities that are transmission-only companies or transcos, *i.e.*, companies that do not own or control generation, do not use their own transmission systems to sell their own power. However, a public utility transco would be required to offer open access transmission services as well as ancillary services. It would also have to provide a real-time information network, as discussed below. The Commission is also announcing certain quality-of-service guidelines to aid in evaluating the quality of transmission service that must be provided by public utilities. These are described *infra* and are reflected in proposed *pro forma* point-to-point and network tariffs

---

e.g., dispatch service, load following service, imbalance resolution service, reactive power support, and operating reserves. We invite comment on definitions of these terms and their component parts. Regardless, the proposed rule would require that all ancillary services be offered on a non-discriminatory basis.

[177] See generally William W. Hogan, Reshaping the Electricity Industry, Prepared for the Federal Energy Bar Conference, ''Turmoil for the Utilities,'' 5 Washington, D.C. (Nov. 17, 1994):

Commercial functions must facilitate non-discriminatory, comparable open access and support market operations in the competitive sectors. The EPAct requirements and the FERC implementation emphasize the need to obtain market access under terms and conditions that support competition. Everyone should have equal access to and use of essential facilities, particularly transmission, with the rights of ownership limited to compensation consistent with opportunity costs in a competitive market.

[178] See, *e.g., AEP*, 67 FERC at 61,491.

[179] Order Providing Guidance Concerning Pending and Future Proceedings involving Non-discriminatory Open Access Transmission Services, Docket Nos. ER93–540–000, *et al.*

[180] While there may be any number of specific services used by a particular customer, we have concluded, after analyzing the historical types of transmission service tariffs on file, as well as the tariffs filed in the ongoing comparability proceedings, that all transmission services generally fall within these two categories.

[181] A utility's own coordination purchases may involve hourly scheduled transfers of fixed blocks of power. These schedules are supported by the utility's own network transmission service used for its economic dispatch. Consequently, network service is covered by the proposed rule because it supports a utility's coordination purchases, regardless of whether or not the utility has any requirements customers that also would use network service.

[182] ''Wheeling through'' refers to transmittal of electric energy through a transmitting utility's grid, *i.e.*, entering at one point of interconnection and leaving at another.

[183] This would be true of other services as well.

attached to this notice of proposed rulemaking. Our preliminary conclusion is that the provisions contained in the *pro forma* tariffs are the minimum provisions necessary to meet the requirement of non-discriminatory open access. We seek comments on these tariffs.

2. Implementing Non-Discriminatory Open Access: Functional Unbundling

The Commission's preliminary view is that functional unbundling of wholesale services is necessary to implement non-discriminatory open access. Accordingly, the proposed rule requires that a public utility's uses of its own transmission system for the purpose of engaging in wholesale sales and purchases of electric energy must be separated from other activities, and that transmission services (including ancillary services) must be taken under the filed transmission tariff of general applicability. The proposed rule does not require corporate unbundling (selling off assets to a non-affiliate, or establishing a separate corporate affiliate to manage a utility's transmission assets) in any form, although some utilities may ultimately choose such a course of action. The proposed rule accommodates corporate unbundling, but does not require it.

Functional unbundling means three things. First, it means that a public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability under which others take service. New wholesale sales and purchases are those under any contracts executed on or after the open access tariffs required by this proposed rule become effective. Non-discriminatory service requires that the utility charge itself the same price for these services that it charges its third-party wholesale transmission customers. We seek comment as to the appropriate means to enforce this requirement, such as a revenue crediting mechanism.

Second, functional unbundling means that a transmission owner must include in its open access tariffs separately stated rates for the transmission and ancillary service components of each transmission service it provides. [184] The rates must satisfy the Commission's Transmission Pricing Policy Statement. Third, functional unbundling means that the public utility, in order to provide non-discriminatory open access to transmission and ancillary services information, must rely upon the same electronic network that its transmission customers rely upon to obtain transmission information about its system when buying or selling power.

For example, the proposed rule requires that a public utility unbundle its new wholesale requirements service contracts, and its new wholesale coordination purchase transactions, and take the firm network transmission component of those services under its own firm network transmission tariff. Similarly, the proposed rule requires that a public utility unbundle any new wholesale coordination sales transactions and take the point-to-point transmission component of that service under its own point-to-point transmission tariff. Finally, the proposed rule requires that a utility unbundle ancillary services and take these services under its network and point-to-point tariffs.

Public utilities also must authorize their power pool agents to offer any transmission service available under power pool arrangements to all transmission customers. In addition, public utilities that participate in a power pool that acts as a control area must authorize the power pool's control center to offer ancillary services under a filed tariff, and must take all of their control area services from that tariff. [185] A public utility must take dispatch service and other ancillary transmission services on the same terms and conditions as those offered to its transmission customers. [186]

The requirement to provide ancillary services and to take those services under a tariff is not intended to mandate any federal rules that would prescribe the actual merit order of dispatch. Rather, it is a requirement that public utilities ensure that dispatch practices and procedures applicable to them are also applied to third-party transmission customers.

The proposed requirement that a public utility take transmission service used for wholesale requirements service and wholesale coordination transactions under its own filed tariff means that all wholesale trade, both that of the public utility and its competitors, would be taken under a single wholesale transmission tariff. Our preliminary view is that such a requirement places the correct incentives on the public utility to file a fair tariff since it must live under those terms for wholesale purposes. The Commission invites comment on its approach to functional unbundling. Will it provide strong enough incentives for non-discriminatory access without some form of corporate restructuring? If utilities restructure, how will our proposed rules apply to different types of corporate structures?

While this approach to unbundling creates good incentives with respect to wholesale service, it omits retail service. In other words, it does not require the transmission owner to take unbundled transmission service under the same tariff as third parties in order to serve its retail customers. This will result in service under two separate arrangements—an explicit wholesale transmission tariff filed at the Commission and an implicit retail transmission tariff governed by a state regulatory body. It also raises the possibility that the quality of transmission service for retail purposes will be superior to the quality of transmission service offered for wholesale purposes.

We seek comment on how this bifurcated approach would affect the public utility's incentives to provide non-discriminatory open access wholesale transmission service. For example, will planning of incremental transmission facilities be comparable or will the transmission provider's retail customers retain an advantage from having expansion costs placed on third parties? What would be the benefits of an approach that required the transmission provider to take unbundled transmission service for both wholesale and retail purposes under the same tariff used by third-party transmission customers? Is such an approach necessary to ensure that all participants have the same incentives to achieve non-discriminatory open access transmission service and competitive power markets? What would be the disadvantages, if any, of such an approach?

The Commission recognizes that the unbundling of transmission for retail purposes would intrude upon matters that state commissions have traditionally regulated. One possible approach that would unify service standards for wholesale and retail

[184] This means that a customer who buys both generation and transmission services from the utility will have a separately stated rate for the generation, transmission, and ancillary services that it purchases. The rates for transmission and ancillary services would be stated in the open access tariff. The rates for the generation service would be under a separate rate schedule.

[185] Similarly, public utilities that own transmission, but get their ancillary services from another entity must authorize that entity to provide ancillary services under a filed tariff and must take their ancillary services from that tariff.

[186] The Commission recognizes that the proposal here overlaps with the pending Pooling Notice of Inquiry. However, the fundamental non-discrimination requirements of the FPA, and therefore the basic requirements of the proposed rule, must be applied to power pools in which public utilities participate. This issue is discussed further in the Implementation Section, *infra.*

service would be for each vertically integrated utility to establish a distribution function that would be responsible for obtaining transmission service on behalf of retail customers. This distribution function then could be treated just as any other wholesale customer. The distribution function of the utility would take service under the single Commission filed tariff. This could change the traditional approach of state-federal allocation of transmission costs. The Commission seeks comment on the merits of such an approach. How could the Commission cooperate with state commissions if it were to adopt such an approach?

Finally, we address a specific type of retail service that we believe to be ''bundled'' retail service in name only: a so-called ''buy-sell'' transaction in which an end user arranges for the purchase of generation from a third-party supplier and a public utility transmits that energy in interstate commerce and re-sells it as part of a ''bundled'' retail sale to the end user. We have determined that in these types of transactions the retail ''bundled'' sale is actually the functional equivalent of two unbundled retail sales: (1) A voluntary sale of unbundled transmission at retail in interstate commerce, subject to our exclusive jurisdiction;[187] and (2) a sale of unbundled generation at retail, subject to the state's jurisdiction.[188] For these types of sales, public utilities will have to provide the voluntary retail transmission component of the sale under a FERC-filed tariff consistent with the substantive requirements of this proposed rule.

We are aware that some public utilities are already contemplating initiating this type of ''buy-sell'' service. Similar services occurred in the natural gas area, but the Commission did not address the jurisdictional issue until a substantial number of transactions had been negotiated and implemented. When the Commission ultimately addressed the natural gas buy-sell programs, we concluded that we have jurisdiction over buy-sell transactions since such agreements utilize interstate transportation.[189] We were concerned then, just as we are concerned now, that interstate and intrastate programs operate together in an appropriately integrated way.[190] It is our preliminary view that the interstate transmission aspect of the buy-sell program must take place under a FERC-filed tariff.

In imposing this requirement we wish to stress that the state has jurisdiction to determine which group of retail customers may participate in such a program. We also recognize that state regulatory commissions will be called upon to determine whether they have jurisdiction under state law over retail wheeling or direct access programs and, if so, whether to authorize such programs.[191] However, the rates, terms, and conditions for the interstate transmission aspects of the program are jurisdictional to this Commission.

The Commission did not address this jurisdictional issue at an early state in the evolution of competition in the natural gas market. Consequently, when we finally acted we chose to grandfather ongoing programs so that energy supply arrangements would not be disrupted.[192] We do not want to face that difficulty again. Thus, we are addressing the issue at an early stage so that public utilities and their customers will be on notice of the jurisdictional implications of their actions, and can make plans accordingly.

3. Real-Time Information Networks

With this proposed rule, the Commission is issuing a Notice of Technical Conference and Request for Comments on a proposal to require that public utilities provide all transmission users, including the transmission owner or controller, simultaneous access to transmission and ancillary services information through real-time information networks that would operate under industry-wide standards. Based upon the lessons we have learned from our experience with gas pipeline EBBs, we believe the proposed approach is necessary and can work.

4. Non-Discriminatory Open Access Tariff Provisions

It is important that the tariffs filed to meet the non-discriminatory open access service requirement contain terms and conditions necessary to ensure a certain minimum level of service quality and to provide a level of certainty to both customers and transmission service providers as to procedures and obligations. The discussion in this section is intended to give guidance about our proposed non-discriminatory open access requirements. The terms and conditions discussed here are reflected in the *pro forma* tariffs in Appendices B and C.[193]

We note at the outset two basic principles proposed to be used when evaluating tariff terms. First, the terms and conditions governing service should be clear and specific. Vague or general tariff terms introduce uncertainty, controversy and delay. In many situations, delaying access or increasing the transaction cost of access is, for all practical purposes, denying access. Second, any restrictions or limitations on service or procedures must be limited to technical or operational needs that can be verified, and they must be the least restrictive way to meet those needs.[194]

The Commission invites comment on the terms and conditions proposed as well as whether others may be necessary.

a. *Customer eligibility.* A non-discriminatory open-access tariff must be available to any entity that can request transmission services under section 211.[195]

b. *Expansion obligation.* A public utility must offer to enlarge its transmission capacity (or expand its ancillary service facilities) if necessary to provide transmission services. This provision is necessary to mitigate the utility's transmission market power that could be exercised by restricting capacity. The customer must agree to reasonable terms, conditions and prices, including the financial responsibility for its share of the incremental expansion costs.[196]

The Commission recognizes that a utility may not be able to enlarge transmission capacity because it cannot obtain the necessary approvals or property rights under applicable

[187] As discussed *infra*, there would be a component of local distribution in such a transaction, subject to the state's jurisdiction.

[188] This determination is consistent with our findings regarding similar types of transactions in the natural gas area. See *El Paso Natural Gas Company*, 59 FERC ¶ 61,031 (1992), *dismissed sub nom. Windward Energy and Marketing Company* v. *FERC*, No. 92–1208 (D.C. Feb. 2, 1994).

[189] *Id.*

[190] 56 FERC ¶ 61,289 at 62,133 (1991).

[191] This Commission does not have authority to order retail wheeling. Section 212(h) of the Federal Power Act, as amended by the Energy Policy Act of 1992, Pub. L. 102–486, 106 Stat. 2776.

[192] 59 FERC ¶ 61,031 (1992); *reh'g denied*, 60 FERC ¶ 61,117 (1992).

[193] These Appendices will not appear in the **Federal Register**.

[194] However, as discussed *infra*, in determining the level of capacity that must be made available for new transmission service requests, we have proposed that capacity needed to meet current and reasonably forecasted native load and to meet existing contractual obligations may be excluded from capacity made available for new transmission service requests.

[195] Under section 211, any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale may request transmission services under section 211.

[196] *See, e.g.*, Northeast Utilities Service Company, 56 FERC ¶ 61,269 at 62,022 (1991), *order on reh'g*, 58 FERC ¶ 61,070, *reh'g denied*, 59 FERC ¶ 61,042 (1992), remanded, 993 F.2d 937 (1st Cir. 1993), *order on remand*, 66 FERC ¶ 61,332 (1994) (*Northeast Utilities*) (wheeling customer must provide reasonable financial assurance before the public utility undertakes substantial investments in new facilities for that customer).

Federal, state and local laws. If the utility has failed after making and documenting a good faith effort to obtain the necessary approvals or property rights, it can request to be relieved of its expansion obligation by an appropriate filing at the Commission.[197] This will result in consistent treatment under FPA sections 205 and 206 and FPA section 211.

c. *Service obligation.* The transmission tariff must offer non-discriminatory transmission services (including related ancillary services that the utility can provide) to eligible transmission customers. For example, a tariff should make available both flexible (*i.e.*, firm and non-firm) point-to-point transmission service and network transmission service, as well as those ancillary services necessary to accomplish such transmission services.

(1) Network Transmission Service. Network transmission service allows a transmission customer to use the entire transmission network to provide generation service for specified resources and specified loads without having to pay a separate charge for each resource-load pairing. Such service allows a transmission customer to integrate, plan, commit, economically dispatch, and regulate its resources to serve its consolidated load. Network service provides the customer with the same flexible network usage needed to optimize its resources to meet its customers' needs that transmission owners have to optimize their resources to meet their customers' needs. Network service includes the ability to import power from other control areas to economically and reliably serve the customers' load. Non-discrimination requires that network service be made available in an open access tariff.

Network service would be valuable to customers such as municipals, cooperatives, and municipal joint action agencies that supply the long-term firm power needs of members with multiple loads that are wholly or partly within a single transmission system. Indeed, network service is essential for the resource integration that is needed for efficient operation. For example, a generation and transmission cooperative whose generating facilities and member cooperatives are widely dispersed may not own all of the transmission facilities needed to link the generators with the members' distribution systems. In this case, the cooperative must rely on a transmission-owning utility to provide network service. Without such service, the cooperative would have difficulty supplying reliable, efficient power to its own members.

(2) Flexible Point-to-Point Service. The second required service in a non-discriminatory open access tariff is point-to-point transmission service. Both firm and non-firm service must be available on a point-to-point basis. Under firm point-to-point service, the transmission owner would provide firm deliveries of power from designated points of receipt to designated points of delivery. Each point of receipt would be set forth in a service agreement along with a corresponding capacity reservation for that point of receipt. Each point of delivery would be set forth in the service agreement along with a corresponding capacity reservation for that point of delivery. The greater of (1) the sum of the capacity reservations at the point(s) of receipt, or (2) the sum of the capacity reservations at the point(s) of delivery would be the firm capacity reservation for which the transmission customer would be charged.

However, firm point-to-point service must have the same flexibility in use as that available to the transmission provider and obligate the transmission provider to supply non-firm transmission service, if available, over non-designated receipt and delivery points (or over designated receipt and delivery points in excess of its firm reservation at those points) without incurring any additional charges (or executing a new service agreement) so long as the customer's use does not exceed its total firm capacity reservation. Any use by a customer in excess of its firm capacity reservation at each point of receipt or point of delivery will be on an as-available basis and will be treated as non-firm service. A customer may also request non-firm point-to-point transmission service on a stand-alone basis.

Transmission customers may be willing to trade off the higher risk of interruption with non-firm service for the lower non-firm transmission rate. Customers should be able to make that choice, which will depend on their own balancing of the risk of transmission service interruption with the interruptibility of, and trade gains associated with, the power resource. It is important that the customer, not the transmission provider, make this choice. The tariff should not restrict non-firm transmission service to the transporting of only non-firm power transactions.[198]

Tariffs should offer flexible point-to-point transmission service for transactions that involve power flows into, out of, within or through the control areas. Whether or not a transmission provider actually undertakes such specific services on its own behalf, it has the flexibility to do so. Therefore, if service to third parties is to be non-discriminatory, they, too, must have such flexibility. In addition, tariff restrictions on receipt and delivery points should not preclude particular types of transactions. For example, a transmission provider should not limit receipt and delivery points to points of interconnection with other transmission systems because such a restriction may preclude transactions that originate or terminate with generation or particular loads within a transmission provider's control area.

(3) Ancillary Services. Ancillary services are those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. Basic transmission service without ancillary services may be of little or no value to prospective customers. A variety of ancillary services is needed in conjunction with providing basic transmission service to a customer. These services range from actions taken to effect the transaction (such as scheduling and dispatching services) to services that are necessary to maintain the integrity of the transmission system (such as load following, reactive power support, and system protection services). Other ancillary services are needed to correct for the effects associated with undertaking a transaction (such as loss compensation and energy imbalance services). Due to the nature of certain ancillary services (such as scheduling and dispatching service), the transmission provider may be uniquely positioned to provide these services. However, for other ancillary services (such as loss compensation service), the customer may wish to provide the service itself or purchase the service from a party other than the transmission owner or its agent.

If the transmission provider provides the ancillary services for its own use of the transmission system, the public utility should offer in the tariff to provide ancillary services for transmission customers. Tariffs should

[197] However, we have previously noted that a utility may bear a heavy burden in demonstrating that it cannot enlarge its transmission capacity to meet a new transmission request. See *Northeast Utilities,* 58 FERC at 61,209.

[198] See Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,767, *order on reh'g,* 60 FERC ¶ 61,168 (1992), *rev'd on other grounds sub nom. Cajun Electric Power Cooperative, Inc.* v. *FERC,* 28 F.3d 173 (D.C. Cir. 1994).

commit to provide specific ancillary services at specific prices or under specific compensation methods that are clearly described.

If the transmission provider obtains ancillary services from a third party, *e.g.*, does not operate its own control area or obtains ancillary services from a pool, the transmission provider should offer in the tariff to secure ancillary services for transmission customers from that third party. Examples of such third-party arrangements may include a public utility obtaining ancillary services from a power pool or from a control area operator.

Based on our experience to date, we propose that the following ancillary services should be offered in the tariff:

1. Reactive Power/Voltage Control Service

In order to maintain transmission voltages on the transmission provider's transmission facilities within acceptable limits, transmission facilities and some or all generation facilities (in the service area where the transmission provider's transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, the need for reactive power/voltage control service must be considered for each transaction on the transmission provider's transmission facilities. The amount of reactive power/ voltage control service that must be supplied with respect to the transmission customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the transmission provider.

The transmission provider will be responsible for providing the necessary transmission-related reactive power support. A transmission customer may elect (or arrange through a third party) to supply some or all of the necessary generation-related reactive power/ voltage control support to the extent that it (or the third party) has the ability to supply such reactive power. If the transmission customer elects (or arranges through a third party) to provide reactive power/voltage control support, such service must be coordinated with the transmission provider (or the entity that is responsible for the operation of the transmission provider's transmission facilities). Alternatively, the transmission provider will supply the necessary generation-related reactive power/voltage control support.

2. Loss Compensation Service

Capacity and energy losses occur when a transmission provider delivers electricity across its transmission facilities for a transmission customer. A transmission customer may elect to (1) supply the capacity and/or energy necessary to compensate the transmission provider for such losses, (2) receive an amount of electricity at delivery points that is reduced by the amount of losses incurred by the transmission provider, or (3) have the transmission provider supply the capacity and/or energy necessary to compensate for such losses.

3. Scheduling and Dispatching Services

Scheduling is the control room procedure to establish a pre-determined (before-the-fact) use of generation resources and transmission facilities to meet anticipated load (including interchange). Dispatching is the control room operation of all generation resources and transmission facilities on a real-time basis to meet load within the transmission provider's designated service area (or other larger area of coordinated dispatch operation). Scheduling and dispatching services are to be provided by the transmission provider or other entity that performs scheduling and dispatching for the transmission provider's service territory.

In certain regions, dynamic scheduling is also allowed. Dynamic scheduling involves responding to load changes or controlling generation within one transmission provider's service territory (or other larger area of coordinated dispatch operation) through the real-time control and dispatch of another transmission provider. Under dynamic scheduling, the operator of an area of coordinated dispatch (control area) agrees to assign certain customer load or generation to another area of coordinated dispatch, and to send the associated control signals to the respective control center of that area. Dynamic scheduling is implemented through the use of special telemetry and control equipment. The transmission customer must be allowed to use dynamic scheduling when it is feasible and reliable.

4. Load Following Service

Load following service is necessary to provide for the continuous balancing of resources (generation and interchange) with load under the control of the transmission provider (or other entity that performs this function for the transmission provider). Load following service is accomplished by increasing or decreasing the output of on-line generation (predominantly through the use of automatic generating control equipment) to match moment-to-moment load changes. The obligation to maintain this balance between resources and load lies with the transmission provider (or other entity that performs this function for the transmission provider). Because of the nature of this service, the transmission provider (or other entity that performs this function for the transmission provider's facilities) may be uniquely positioned to provide load following service. Therefore, unless the transmission customer is able to obtain such service from its own generation or from third-party generation that is capable of supplying such service in accordance with conditions generally accepted in the region and consistently adhered to by the transmission provider, the transmission provider will supply load following service.

5. System Protection Service

A transmission provider must have adequate operating reserves or other system protection facilities available in order to maintain the integrity of its transmission facilities in the event of (1) unscheduled outages of a portion of its transmission facilities or facilities connected to the transmission provider's service territory or (2) unscheduled interruption of energy deliveries to the transmission provider's transmission facilities. The amount of system protection service that must be supplied with respect to the transmission customer's transaction will be determined based on operating reserve margins or other relevant criteria that are generally accepted in the region and consistently adhered to by the transmission provider.

The transmission customer may elect or arrange through a third party to provide resources that are sufficient to satisfy the system protection needs of the transmission provider. Operation and dispatch of such resources must be coordinated with the transmission provider or other entity that maintains operating reserves and other system protection facilities for the transmission provider's service territory.

6. Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the hourly scheduled amount and the hourly metered (actual delivered) amount associated with a transaction. Typically, an energy imbalance is eliminated during a future period by returning energy in-kind under conditions similar to those when the initial energy was delivered.

The transmission provider shall establish a deviation band (e.g., +/−1.5 percent of the scheduled transaction) to be applied hourly to any energy imbalance that occurs as a result of the transmission customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within 30 days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the transmission provider. If an energy imbalance is not corrected within 30 days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the transmission provider, the transmission customer will compensate the transmission provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the transmission provider. To the extent another entity performs this service for the transmission provider, charges to the transmission customer are to reflect only a pass-through of the costs charged to the transmission provider by that entity.

We seek comment on our proposed treatment of ancillary services. Are there alternative ways to ensure the non-discriminatory provision of ancillary services? We also seek comment on the above-described ancillary services. Are they the appropriate ancillary services for the needs of entities seeking transmission service? Are the descriptions of the ancillary services appropriate? Should any of the described services not be offered, and if so, why? Are there other ancillary services that should be offered? Should all ancillary services be offered as discrete services with separate prices, or should certain ancillary services be offered as a package? Additionally, we seek comment on whether the additional complexity of obtaining ancillary service externally from the host control area with the use of dynamic scheduling is the appropriate course to follow.

d. *Service Periods.* The duration of service reservations should not be unduly limited. Non-discriminatory service requires any such limits on third-party service to be the same as those the transmission provider or controller faces. In particular, the tariff should allow firm service contracts to extend at least for the life of a customer's power plant or purchase contract. Power developers are unlikely to build new plants if they cannot secure firm transmission services for the plant's life. Integrated transmission owners plan their transmission systems to ensure capacity to deliver the output of their own planned generation units. Non-discriminatory service requires the same for transmission-only customers. Likewise, the minimum duration for service should be the same as the minimum scheduling period of the transmission owner. All minimum or maximum restrictions must be justified on a technical or operational basis.

e. *Reassignment Rights.* A tariff must explicitly permit reassignment of firm service entitlements. Capacity reassignment rights can have a number of benefits. First, reassignment rights are important in helping transmission users manage the financial risk associated with long-term commitments to take transmission service. A robust reassignment market would aid, among others, customers who can get or must take transmission capacity now but do not actually need it until some time in the future, and customers whose need for capacity they have under contract is intermittent or suddenly declines. Transmission owners have the flexibility to manage this sort of risk by offering transmission capacity to others. Non-discriminatory service demands that non-owner holders of rights to transmission capacity have the same flexibility to manage their risk as owners have.

Second, capacity reassignment, combined with assured access to firm transmission service, reduces the transmission provider's market power by enabling transmission customers to compete with the owner to some extent in the firm transmission market. To promote competition in such a secondary market, firm service rights should be defined as broadly as possible, consistent with reliable operation of the system. In particular, using firm transmission capacity to deliver non-firm power or repackaging firm transmission capacity for sale as non-firm capacity should not be unduly restricted.

Third, the ability to reassign capacity rights can also improve capacity allocation. When capacity is constrained and some market participants value capacity more than current capacity holders, the current holders may be willing to reassign their capacity rights at rates below the opportunity costs of the transmission provider, thereby lowering rates to the new customer. We note that the prices of reassignments are currently capped at the price the public utility sold the transmission.[199] The Commission invites comments on whether the current price cap on resale should be modified or eliminated.

In addition, the service agreement must state clearly the respective obligations of the original right holder and any subsequent purchaser of the right. In particular, it should state the conditions, if any, under which the original right holder can be released from its obligations under the service agreement if the right is reassigned or sold. Any reassignments must be done in a not unduly discriminatory manner. We invite comment on these reassignment issues.

Given the current specification of basic transmission services (network, flexible point-to-point, and ancillary), some services may be more reassignable than others. The ease with which rights can be reassigned depends on two factors: the ability of ensuring operational feasibility and the specificity of contract rights. Point-to-point service involves a well-specified right to transfer a given amount of power between specific points or across an interface under certain conditions. The transmission provider is operationally indifferent as to who wants to transfer the power that flows between those points. Thus, point-to-point service is well-suited to reassignment.

Network service, as currently defined, is idiosyncratic because it is unique to the transmission user receiving the service. This service is purchased to integrate a set of resources into a set of loads given specific dispatch parameters and load profiles. The transmission provider has to plan and operate its system for this specific service. It is not clear that such service could be of any value to an entity other than the original buyer. It is also not clear precisely what would be resold because network customers do not have rights to a specific amount of transmission capacity, but have rights only to a varying amount of capacity needed to integrate load with their dispersed power resources.[200] Such indeterminate rights may not be amenable to reassignment. We seek comments on reassigning network service. Can network service be structured such that

[199] See *Florida Power & Light Company,* 66 FERC ¶61,227 at 61,524 (1994), *order on reh'g,* 70 FERC ¶61,150 (1995). The Commission has required a similar cap for released pipeline capacity. See Order No. 636–A, Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol and Order Denying Rehearing in Part, Granting Rehearing in Part, and Clarifying Order No. 636, Ferc Stats. & Regs. ¶30,950 at 30,560 (1992), *appeal pending.*

[200] In *FP&L,* the Commission approved network service billing based on a load ratio method of cost allocation, instead of on contract demand.

capacity rights could be specified and reassigned?

Ancillary services also may not be suitable for reassignment. We seek comments on these reassignment issues.

e. *Reciprocity provision.* The Commission proposes to require that transmission tariffs contain a reciprocity provision.[201] The purpose of this provision is to ensure that a public utility offering transmission access to others can obtain similar service from its transmission customers. It is important that public utilities that are required to have on file tariffs be able to obtain service from transmitting utilities that are not public utilities, such as municipal power authorities or the federal power marketing administrations that receive transmission service under a public utility's tariff.

f. *Available Transmission Capacity (ATC).* ATC is capacity that must be made available for new firm transmission service requests. Basically, it is the capacity not committed to other firm uses during the scheduling interval(s) for which service is requested. The tariff must clearly specify the other uses for which capacity will be excluded from ATC. Acceptable other uses may include:

- A requirement to meet generally applicable reliability criteria.
- Meeting current and reasonably forecasted load (retail customers and network transmission customers) on the transmission provider's system. The term ''reasonably forecasted'' should be defined in terms of the utility's current planning horizon. Capacity needed to serve reasonably forecasted load must be made available until the forecasted load develops.
- Fulfilling the transmission provider's current firm power and firm transmission contracts.
- Meeting pending firm transmission service requests.

In the tariff, the utility must commit to provide an index of other holders of firm transmission entitlements and describe the method used to estimate ATC in sufficient detail to allow others to do the same analysis. The utility must make all data used in calculating the ATC publicly available. The methodology and the data used to develop the ATC must be consistent with the information submitted in the FERC Form No. 715, Annual Transmission Planning and Evaluation Report.[202]

Capacity can be withheld from ATC only if it is to be used during the scheduling period for which service is requested. For example, if a customer requests firm service for ten years and the utility needs that capacity to serve native load during years six to ten, the utility must provide service using the existing capacity for the first five years and then use expanded capacity or some other alternative arrangement for the third-party service during the remainder of the term.

Under the proposed rule, ATC information will be required to be made available in the public utility's information system. The nature of the ATC information to be made available and the manner in which it is made available will be the subject of the real-time information networks technical conference that we are concurrently initiating.

g. *Procedures for obtaining service.* This section must clearly describe all notice and response requirements, including deadlines for each step in the process, the information required in a valid request for service, the procedure for obtaining service from existing capacity and the additional steps to follow when capacity expansion is required. The discussion below highlights some particularly important aspects of procedures for obtaining service.

The tariff must specify minimum notice periods. Notice for accepting requests for short-term service is particularly important. Because market opportunities may be short-lived, the advance notice required for short-term service should be as brief as possible and should be able to be secured through the real-time information network. Similarly, the tariff also should specify the minimum time needed to accommodate customers' needs to plan and construct new generating units or to enter into long-term power supply contracts.

A tariff must specify the information that must accompany a service request. This information should generally track that specified in the Commission's Policy Statement Regarding Good Faith Requests for Transmission Services.[203] The tariff should require only information that is clearly necessary to determine whether capacity is available, the price for the service requested and other information necessary to process the service request.

A tariff may require scheduling of receipt and delivery points and amounts of energy flows but not require disclosure of power contract terms as part of the request process. While the Commission has accepted such a requirement in some tariffs, our preliminary view is that there are less intrusive and less ambiguous ways of dealing with transmission owner concerns. If the concern is the need to know intended power flows, the needed information of the anticipated transaction can be specified in a service request.

The concern may be that a customer will reserve scarce capacity and then hold it without using it (for whatever reason). While reservation holders as well as transmission providers should not be allowed to withhold capacity, there are less restrictive options for dealing with this concern. One is to allow the transmission provider to use or sell the capacity for so long as the reservation holder is not using it. Another is to have a pool that clears the short-term market. Of course, the reservation holder would be compensated. Another option is to require the customer to begin using the capacity within some period or lose its reservation rights for that capacity. Any of these alternatives can allay legitimate concerns without forcing customers to reveal unnecessary details of the transaction. The Commission requests comments on these and other approaches. Could pooling help address these issues? In particular, how would a use-it-or-lose-it rule work? How would a utility know which reservation holder to compensate with non-firm revenues if network service customers hold no reservation rights? Non-firm revenues could be shared among load-ratio customers and reservation customers on the basis of the non-use of the firm entitlements.

With respect to network service, our preliminary view is somewhat different. Because network service is billed on a load ratio basis, customers would have the incentive to specify unlimited generation resources to be integrated into their load without any commensurate financial obligation. The transmission provider would nevertheless have to plan its system to dispatch those resources. Thus, network customers, when designating their network resources, must show that they own or have contracted for those resources. We seek comment on this issue. Are there alternative ways of dealing with this problem for network service?

[201] The Commission previously accepted tariffs that contain reciprocity provisions. See, *e.g., El Paso Electric Company and Central and South West Services Inc.,* 68 FERC ¶61,181 at 61,916 (1994), *reh'g pending; Southwestern Electric Power Company and Public Service Company of Oklahoma,* 65 FERC ¶61,212 at 61,981–82 (1993), *reh'g denied,* 66 FERC ¶61,099 (1994).

[202] See Order Nos. 558 and 558–A, *supra* note 92.

[203] See *supra* note 91.

The tariff should provide that, if service can be provided using existing capacity, a service agreement will be tendered in time for the customer to execute it so that service can begin at the time requested. The tariff should clearly state the applicable rates for service from existing capacity. In addition, the tariff should contain provisions, as well as rates, for reserving capacity now for use at a later time. Also, the tariff should contain a standardized service agreement that applies to all service provided from existing capacity.

When existing capacity is not adequate to provide additional firm service, the tariff should require the transmission provider to prepare, if needed, an engineering study of options for expanding capacity, including the costs of each option, within a specified period. The customer should be required to pay the reasonable costs of performing the study. If the customer elects to take service after reviewing the engineering study and cost estimates, including supporting documentation, the transmission provider may require the customer to enter into a contract, provide a security deposit, and agree to take service at rates calculated in accordance with the pricing provisions of the tariff.[204] The tariff should allow the customer to specify the contract term.

h. *Service priority.* Service priority becomes important when capacity is constrained (*i.e.*, demand exceeds supply). This, in turn, has two aspects: when new service requests are considered and when, after service has begun, interruptions are required.

(1) *Considering new service requests.* A tariff should specify a reasonable basis upon which service requests will be considered. As long as transmission capacity is available for all requests, they can all be accommodated. When capacity is short, however, the priority of requests is important because the determination as to which requests are met from existing capacity and which require expanded facilities will affect pricing. However, firm service requests should always receive priority over non-firm service requests, and firm service requests from third-party transmission customers should have the same priority as new transmission services for the public utility's native load.

The industry currently operates under a contract rights regime whereby customers are given contract rights for a specific period at a set price. Under this regime, requests are generally processed under a first-in-time rule. Capacity is allocated in the order in which the requests were made. If available transmission capacity is exhausted, a requester may be required to pay the incremental cost of relieving the constraint. Incremental cost could be either the redispatch cost of unloading a line or the cost of expanding capacity. Thus, the position of the requester in the queue may affect price and possibly determine when service is provided. Alternatively, all requesters during a given period could be treated as making one request for a large increment of capacity and pay the same average incremental cost. We seek comments on appropriate ways to process requests.

(2) *Allocating interruptions.* After service has begun, priority is important if capacity becomes unexpectedly constrained and service must be interrupted.[205] Contracts must spell out the obligations and priorities in dealing with operating and reliability procedures. Priorities will affect the order in which services are interrupted. A tariff must specify that firm transmission service always has priority over non-firm transmission service. Non-discriminatory service requires that firm transmission customers have the same assurance of uninterrupted use of the grid, within their contractual commitments and obligations, as the transmission provider. That is, the public utility's personnel who trade wholesale power should have the same firm transmission service as does a firm transmission customer. Both have the same standing when the control area operator deals with emergencies. That is, both must recognize that the operator is authorized to interrupt scheduled power transfers as needed in order to maintain reliability. Operators must be allowed to maintain safe and reliable service on the overall system.

Generally, interruption of firm transmission service should occur only because of: (1) Emergencies or *force majeure;* or (2) the need to maintain overall reliability or to protect equipment as prescribed in industry operating guidelines. The specific reasons for interruptions will have to be determined in accordance with the characteristics of each transmission provider's system. The tariff should require the provider to notify all customers in a timely manner of any scheduled interruptions, while recognizing the right to take appropriate actions under operating procedures to deal with unscheduled emergency conditions.

i. *Security deposits and creditworthiness.* A tariff may require that a reasonable, returnable deposit accompany the request for service, and that the customer demonstrate basic creditworthiness. A creditworthiness investigation (including a security deposit requirement) must be applied on a non-discriminatory basis.

j. *Short-term and interruptible service agreements.* A copy of standard transmission service agreements for short-term and interruptible transmission services must be included in the tariff in order to expedite service and limit the possibility of undue discrimination or other abuse. The tariff must list all information needed from the customer.

k. *Dispute resolution.* The tariff must clearly set forth the steps to be followed to resolve disputes. Procedures should be designed to resolve conflicts quickly. This suggests the use of some type of alternative dispute resolution (ADR) process, such as mediation or arbitration. ADR would be especially useful when the dispute is over response times, capacity additions, a highly technical matter, or any matter that applies, but does not extend, existing Commission policy. The tariff should specify which types of disputes must go to ADR and which disputes must be taken directly to this Commission.

A tariff should provide that capacity expansion proceed while cost disputes are pending, provided the customer agrees to pay the costs actually incurred and the rate ultimately determined by the Commission. This is needed to minimize delays when the customer wants the service but disputes the cost. Such a provision would require the transmission owner to proceed with whatever steps are necessary to provide service to the customer, as long as the customer agrees to furnish a deposit and state in writing that it will take service at the rates, terms and conditions that are ultimately found just and reasonable by the Commission, or to pay all out-of-pocket costs incurred in processing the request up to the date of cancellation of the request.

l. *Pricing.* Transmission pricing must be consistent with the Commission's Transmission Pricing Policy

[204] See Energy Services, Inc., 58 FERC ¶ 61,234 at 61,766 and 61,768 (1992) (security deposit or some other form of assurance permitted; approval of provision requiring transmission customers to have ''suitable interconnection agreement'' with transmission-owning utility).

[205] Of course, the utility always may curtail if necessary to maintain the reliability of the system. For example, if a major transmission line fails, the utility may quickly have to interrupt transactions without regard to priority of service in order to stabilize the system. Once the system is stabilized, however, the utility should allocate remaining capacity on the basis of contractual priorities.

Statement.[206] We especially note that the transmission public utility must charge itself the same price for transmission services that it charges its third-party wholesale transmission customers.

5. Pro Forma Tariffs

Appendices B and C to this proposed rulemaking contain *pro forma* tariffs that contain the minimally acceptable terms and conditions of service for point-to-point and network transmission services. They contain tariff language that assures acceptable levels of service quality for non-price terms and conditions. For the most part, we have avoided specifying pricing provisions. The *pro forma* tariff provisions would of course be subject to case specific scrutiny to ensure that services are provided on a non-discriminatory open access basis. We seek comment on whether these tariffs provide a good basis for defining the minimum acceptable non-price terms and conditions of service.

6. Broader Use of Section 211

The Commission intends to exercise its authority under sections 205 and 206, as described in this proposed rule, in a complementary manner with its authority under section 211. Requiring all public utilities to file non-discriminatory open access tariffs, as set forth in this NOPR, will not alone ensure competitive bulk power markets in all regions of the United States. Many utilities providing transmission services are not public utilities subject to our full jurisdiction.[207]

Section 211, however, permits entities to seek open access to all transmission facilities, including those owned by non-public utilities. Thus, to further eliminate unduly discriminatory practices in the industry, the proposed rule encourages the broad use of section 211.

While the Commission cannot order transmission *sua sponte* under section 211, nothing in section 211 prohibits groups of qualified applicants from simultaneously or jointly filing applications for the same service. [208] Such group or joint action would permit the Commission to order tariffs of broader applicability.

Moreover, sections 211 and 212 require that applicants specify only rates, terms, and conditions of service, not specific transactions. Thus, applicants can file requests for tariffs to accommodate future, currently unspecified, short-notice transactions, similar to the type of tariff filed by many utilities seeking approval of market-based rates or mergers.[209]

Section 211 bars the Commission from ordering service that would unreasonably impair the continued reliability of electric systems affected by the order. To meet this requirement, the transmission owner and the applicant (or the Commission if necessary) can craft provisions in the general tariffs discussed above to assure that service will comply with standard industry operating practices and, thus, not have an unreasonable impact on reliability.

Finally, section 211 permits an opportunity for an evidentiary hearing.[210]

Section 211 does not preclude applicants from lodging the record from a section 205 undue discrimination case involving the same service, nor does it preclude the Commission from incorporating and relying on the record and findings in a section 205 proceeding if the section 211 applicant, the transmitting utility, and the service requested are the same. In sum, sections 211 and 212 provide the Commission and the electric industry a much broader means to attain wider transmission access than has been achieved so far. In this regard, the Commission invites comment on further avenues the Commission can pursue to facilitate and expedite 211 applications.

Section 211 also complements our section 205 and 206 authority in that it allows customers to request unique services not available in the non-discriminatory open access tariff. While our objective in this proposed rule is to implement a very broad service commitment in the non-discriminatory open access tariff, customers may have unique service needs that are not contemplated in the open access tariff.

7. Status of Existing Contracts

There are three general types of existing wholesale contracts that could be affected by the proposed rule: (1) Requirements and other firm service contracts under which customers take bundled transmission and generation services; (2) coordination contracts for purchases or sales of economy energy; and (3) transmission-only contracts. The Commission believes that it can eliminate unduly discriminatory practices and achieve more competitive bulk power markets without abrogating existing contracts. Accordingly, as discussed *supra,* we have proposed to apply the unbundling requirement only to transmission services under new requirements contracts and new coordination transactions. In addition, although the open access tariffs must be open to all entities that could request transmission service under section 211, *i.e.,* all non-sham wholesale purchasers, we are not proposing to abrogate any existing power or transmission contracts. However, there may be situations in which it would be contrary to the public interest to allow existing wholesale power or transmission contracts to remain in effect. Accordingly, we invite comment on whether it would be contrary to the public interest to allow all or some of the above types of existing contracts to remain in effect.

8. Effect of Proposed Rule on Commission's Criteria for Market-Based Rates

As stated above, one of the primary reasons for this rulemaking is to foster increased wholesale competition, in order to reduce prices for consumers. Moreover, the increased competition allowed by non-discriminatory open access may allow lighthanded regulation of wholesale sales for many more transactions and perhaps throughout many regions.

The Commission's standards for allowing market-based rates for wholesale power sales require an applicant and its affiliates to demonstrate that they lack or have mitigated market power in generation and transmission, that they cannot erect other barriers to entry,[211] and that there is no affiliate abuse or reciprocal dealing. In *KCP&L,*[212] the Commission

[206] *See supra* note 124.

[207] For example, there are approximately 56 electric utilities operating control areas in the United States that are not public utilities.

[208] This assumes, of course, that all have made the requisite request to the transmitting utility 60 days prior to filing. FMPA, for example, filed on behalf of numerous Florida municipals in the *FP&L* section 211 case. See *Florida Municipal Power Agency* v. *Florida Power & Light Company,* 65 FERC ¶ 61,125 (1993).

[209] See *CSW, supra,* 68 FERC at 61,916. Section 211 bars the Commission from ordering service that would unreasonably impair the continued reliability of electric systems affected by the order. To meet this requirement, the transmission owner and the applicant (or the Commission if necessary) can craft provisions in the general tariffs discussed above to assure that service will comply with standard industry operating practices and, thus, not have an unreasonable impact on reliability.

[210] Such a hearing is required only if there are material issues of fact in dispute. See *Citizens for Allegan County, Inc.* v. *FPC,* 414 F.2d 1125, 1128 (D.C. Cir. 1969).

[211] For applicants with transmission market power, the Commission has required the mitigation of such power through the filing of a non-discriminatory open access tariff. The Commission also has examined an applicant's control over potential barriers to entry, *e.g.,* ownership or control of sites for generation facilities, generation equipment, or pipelines for supplying fuel.

[212] 67 FERC at 61,557.

determined that it no longer needed to examine generation dominance in analyzing market-based rate proposals for sales from new generation facilities. However, the Commission has continued to evaluate generation dominance in analyzing market-based rate proposals for sales from existing generation capacity.[213]

If this rulemaking achieves the Commission's goals, and competition fueled by open access increases in the wholesale bulk power markets to the extent we expect, the increased competition may reduce or even eliminate generation-related market power in the short-term market. Increased wholesale competition could reduce the need for cost-based regulation of bulk power sales and allow broader use of market-based rates. For example, more competitive markets may allow us at some point to drop the generation dominance standard for existing capacity. We believe that the increased competition expected to result from this rulemaking may allow us to consider innovative approaches to authorizing market-based rates for generation. One suggestion in this regard has been that the Commission ought to consider filings made pursuant to section 205 seeking authorization of market-based rates for all sellers in a defined region. For example, such a region conceivably could be defined by the boundaries of an RTG, a power pool, a reliability council, or the less formal boundaries of an economic market. However, before proceeding to consider this suggestion, or any other innovative proposal for dealing with market-based rates for existing wholesale generation, the Commission must address certain threshold questions. Therefore, the Commission solicits comments on the following questions:

(1) Assuming that a final rule in this proceeding mandates that all public utilities must file generally applicable non-discriminatory open access tariffs, would wholesale sellers of generation from existing generating facilities still possess market power?

(a) Can we eliminate our generation dominance standard based on before-the-fact predictions of changes to come from our rulemaking, or must we rely on after-the-fact evidence of the changes that did occur?

(2) For purposes of assessing whether existing wholesale generators still possess market power, how ought the relevant market be defined in an open access transmission environment? To what extent do the boundaries of a regional transmission group, a power pool, or a reliability council lend themselves to being used to define the relevant market in an open access environment?

(3) Should it be determined that, notwithstanding non-discriminatory open access transmission, existing generators still possess market power, can such market power be mitigated effectively to permit market-based rates for existing generation? And, if so, what are the Commission's options? For example:

(a) Ought the Commission rely on rules of conduct, market mechanisms intended to ensure competition in wholesale power sales (such as bidding procedures) and monitoring as the means to curb such market power; or

(b) Ought the Commission rely on structural reforms as the means to curb such market power?

(4) Once the Commission has determined how to define the relevant market in an open access environment, ought the Commission entertain requests that all wholesale sellers within such a market be authorized to charge market-based rates?

9. Effect of Proposed Rule on Regional Transmission Groups

In the Commission's Policy Statement Regarding Regional Transmission Groups (RTGs) we expressed support for the development of voluntary transmission associations and encouraged their formation. We believe that RTGs can speed the development of competitive markets, increase the efficiency of the operation of transmission systems, provide a framework for coordination of regional planning of the system and reduce the administrative burden on the Commission and on members of RTGs by providing for voluntary resolution of disputes.

Since the issuance of the Policy Statement, the Commission has given conditional approval to the bylaws of two RTGs.[214] Both approvals were conditioned on the members agreeing to offer comparable transmission services at least to other members, through either individual transmission tariffs or a generic regional tariff. For public utilities, that condition would be superseded by fulfillment of the requirements of the proposed rule.

To the extent public utilities view the comparability requirement in our two RTG orders as a disincentive to joining an RTG, that disincentive would be mooted. All such utilities will be required to file tariffs. Moreover, we will continue to provide substantial latitude for innovative pricing proposals by an RTG, as indicated in the Transmission Pricing Policy Statement.

Some transmission users might conclude that the availability of comparability tariffs makes membership in an RTG less necessary. But, this conclusion would ignore the comparative benefit of a member having its needs planned for on a region-wide basis under an RTG instead of on a system-by-system basis. Coordination of planning that results in a more efficient system creates economies for both transmitting utilities and users.

Also, the reduction in administrative burden for all parties involved in an RTG would remain. RTG members can work out their own disputes without incurring the substantial costs and delays involved in litigating at the Commission or in the courts. This fact alone makes for more flexible and responsive markets and reduces costs. Moreover, the Commission has stated its willingness to give deference to decisions resolved through RTG dispute resolution procedures.

In short, RTGs are still a valuable tool in promoting wholesale competition and in achieving other Commission goals. RTGs are structures to reflect the interests of all of the grid's users, not just some. RTGs allow for consensual solutions to local or regional issues, instead of solutions imposed by FERC. RTGs can function as regional laboratories for experimentation on transmission issues. And, RTGs will provide a regional forum, a necessary predicate to regional cooperation. The potential benefits of RTGs would in no way be undermined by the rules proposed in this Open Access NOPR.

F. Stranded Costs and Other Transition Costs

1. Supplemental Notice of Proposed Rulemaking on Stranded Costs by Public Utilities and Transmitting Utilities

a. Introduction. The Commission's Open Access NOPR would impose significant new requirements on public utilities—requirements that would help us to achieve the goal of robust competitive wholesale power markets, and that would result in a new way of doing business for utilities. The Open Access NOPR would give a utility's historical wholesale customers enhanced opportunities to reach new suppliers and, therefore, would affect the way in which utilities traditionally have recovered costs. We believe it is essential to address the transition issues associated with the move toward competition responsibly. The most significant of these issues is stranded cost recovery.

The recovery of legitimate and verifiable stranded costs is critical to the successful transition of the electric utility industry from a tightly regulated, cost-of-service industry to an open

[213] See *Entergy Services Inc.*, 58 FERC ¶61,234 at 61,755 (1992).

[214] See *SWRTA* and *WRTA*, supra.

transmission access, competitively priced industry. Public utilities have invested billions of dollars in facilities built under a regulatory regime in which they have been permitted to recover all prudently incurred costs, plus the opportunity to earn a reasonable rate of return on their investment. [215] At the wholesale level (and in some instances the retail level), they are now entering a regulatory era in which they will have to compete to supply electric service. We believe that utilities should be allowed to recover the costs incurred under the old regulatory regime according to the expectations of cost recovery established under that regime.

The primary goal of the Open Access NOPR is to promote competitive wholesale markets by assuring that all wholesale sellers of generation have the opportunity to compete on a fair basis and that all wholesale purchasers can reach alternative sellers. Ultimately, this should result in lowering electricity prices for the Nation's consumers. In the meantime, however, if a wholesale customer is able to leave its existing generation supplier to shop for power elsewhere, we do not believe the existing supplier's shareholders or its remaining customers should have to bear costs that were prudently incurred under the old regulatory system to serve the departing customer.

We cannot successfully and fairly encourage the development of competitive wholesale markets as envisioned by the Open Access NOPR until we have made provision for electricity suppliers to seek recovery of existing uneconomic costs (primarily generation) which they already have incurred (*i.e.*, those that could not earn a reasonable return in a competitive market). Recovery of legitimate and verifiable transition costs will permit all sellers, including the utilities who prudently incurred these costs, to compete on a more equal footing in competitive bulk power markets. In addition, while stranded cost recovery may delay some of the benefits of competitive bulk power markets for some customers, the Commission learned from its experience in the restructuring of the natural gas industry that these types of transition costs must be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets. [216]

The Commission believes that the approach proposed in the Stranded Cost NOPR issued on June 29, 1994 [217] should adequately cover most, if not all, costs that could be stranded in an environment where transmission access is more widely available, including the access environment that the Commission expects if the provisions of the Open Access NOPR are adopted. Some of the mechanisms proposed in the initial NOPR have been revised in this Supplemental NOPR to reflect submitted comments. In addition, there may be implementation or other issues raised by the open access requirements that were not contemplated when the Stranded Cost NOPR was originally proposed. Accordingly, we are issuing a Supplemental Notice of Proposed Rulemaking on Stranded Costs. In this Supplemental NOPR, we make preliminary determinations [218] on certain issues and seek additional comments limited to the new matters proposed in this document, including the proposed open access requirements. We also propose to permit public utilities and transmitting utilities to seek recovery through transmission rates of stranded costs associated with a discrete set of existing wholesale requirements contracts.

b. Summary of Major Preliminary Determinations. In response to the June 29 Stranded Cost NOPR, the Commission received initial and/or reply comments from 128 entities, representing a broad cross-section of parties that participate in, or are affected by, the electric utility industry.[219] The Commission has carefully reviewed all of the comments, and made several preliminary determinations. First, we have determined that recovery of legitimate and verifiable stranded costs should be allowed, and that direct assignment of stranded costs to departing customers, as proposed in the Stranded Cost NOPR, is the appropriate method for recovery.[220]

Second, with respect to stranded costs associated with new wholesale requirements contracts, [221] we reaffirm our proposal that a public utility may not seek recovery of such costs except in accordance with an exit fee or other explicit provision contained in the contract. The public utility may seek recovery in accordance with the contract. However, no public utility or transmitting utility may seek recovery of stranded costs associated with new requirements contracts through any transmission rate under section 205, 206 or 211.[222]

Third, with respect to stranded costs associated with existing wholesale requirements contracts [223] that are not renewed and that do not contain exit fees or other stranded cost provisions, if the seller can demonstrate that it had a reasonable expectation that the contract would be renewed and can meet other evidentiary criteria, we believe that stranded cost recovery should be allowed. We encourage the parties to such contracts to attempt to negotiate a mutually agreeable stranded cost amendment. We have determined, however, that the three-year negotiation period proposed in the initial Stranded Cost NOPR should be abandoned. We propose instead that: (1) A public utility or its customer under the contract may, at any time prior to the expiration of the contract, file a proposed stranded cost amendment to the contract under section 205 or section 206; or (2) a public utility may, at any time prior to the expiration of the contract, file a proposal to recover stranded costs through transmission rates for a departing customer.[224] We believe it is

[215] Many also have committed millions of dollars to purchase power under long-term power supply contracts.

[216] See AGD, supra note 9, 824 F.2d at 1021–30. However, our mechanisms for addressing stranded costs in the electric industry differ from those used in the gas industry for the reasons discussed below.

[217] See supra note 5.

[218] If we were not issuing the Open Access NOPR, we would be inclined to adopt a final rule on stranded costs at this time. However, we are concerned that the Stranded Cost NOPR might not provide appropriate mechanisms to address transition costs that could result from the open access environment envisioned by this NOPR. Accordingly, our findings here are interlocutory in nature, and rehearing does not lie.

[219] A list of commenters is attached as Appendix D.

[220] As discussed *infra*, section III.F.1.c(13), however, this does not foreclose case-specific proposals for dealing with stranded costs in the context of voluntary corporate restructuring proceedings.

[221] For recovery of wholesale stranded costs, the proposed rule distinguishes between stranded costs associated with wholesale requirements contracts executed after July 11, 1994, the date the proposed rule was published in the **Federal Register** (''new'' contracts) and stranded costs associated with wholesale requirements contracts executed on or before that date (''existing'' contracts). Stranded Cost NOPR at 32,860.

[222] As we indicated in the Stranded Cost NOPR, if the seller under a new wholesale requirements contract is a transmitting utility subject to the Commission's jurisdiction under section 211 of the FPA, but not also a public utility subject to the Commission's section 205–206 jurisdiction, there will be no Commission forum for addressing wholesale stranded costs associated with the new contract. Such utilities will not be able to seek recovery of wholesale stranded costs associated with such new contracts through rates for transmission services ordered under section 211, and the Commission does not have jurisdiction over their power sales contracts. Therefore, these utilities must address recovery of stranded costs through their new wholesale requirements contracts subject to the appropriate regulatory authority approval. Stranded Cost NOPR at 32,860–61.

[223] Existing wholesale power sales contracts are those contracts executed on or before July 11, 1994. Stranded Cost NOPR at 32,860, 32,881.

[224] If the selling utility under the existing contract is a transmitting utility that is not also a public utility, its wholesale requirements contracts are not

in the public interest to permit public utilities to seek recovery of stranded costs associated with existing contracts that do not explicitly address stranded costs, and that they be permitted to do so either through transmission rates or through amendment to the existing power sales contracts. However, for a utility to be eligible for stranded cost recovery, it must meet the evidentiary demonstration required by this rule.

In examining proposals to recover stranded costs, we propose to apply a ''reasonable expectation'' standard and a rebuttable presumption that if contracts contain notice provisions, the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision. We further propose to retain the requirement in the initial Stranded Cost NOPR that utilities attempt to mitigate stranded costs. In addition, we are proposing that public utilities be required to follow certain procedures specified herein that permit a customer to obtain advance notice of its maximum possible stranded cost exposure without mitigation.[225]

Fourth, with respect to costs stranded as a result of retail wheeling, or as a result of wholesale wheeling obtained by a retail-turned-wholesale customer, the Stranded Cost NOPR explored the issue of whether we should assume some responsibility for addressing such costs. The vast majority of those commenting on our proposed rule urged us not to get involved or otherwise assume responsibility for those types of stranded costs, except in certain very limited circumstances. At this juncture, we have concluded that it is appropriate to leave it to state regulatory authorities to assume the responsibility for any stranded costs occasioned by retail wheeling, except in the narrow circumstance in which the state regulatory authority does not have authority under state law, at the time retail wheeling is required, to address recovery of such costs. The Commission holds the strong expectation that states will provide procedures for, and the full recovery of, legitimate and verifiable stranded costs.

We also have determined that this Commission should be the primary forum for public utilities to seek recovery, through FERC jurisdictional transmission rates, of stranded costs resulting from wholesale wheeling for newly created wholesale customers who leave their franchised utility's supply system (e.g., through municipalization).[226]

In deciding that states are the more appropriate entities to address stranded costs resulting from retail wheeling, we are relying on assurances from our state colleagues, as evidenced, for example, in NARUC's comments on the proposed rule, that they will address and resolve this difficult issue. We continue to be of the opinion that utilities are entitled, from both a legal and policy perspective, to an opportunity to recover their past prudently incurred costs, including costs incurred to serve retail customers who obtain retail wheeling in interstate commerce. We emphasize that we will not allow states to use rates for transmission in interstate commerce as the vehicle for passing through any stranded costs resulting from retail wheeling, except in the narrow circumstance described. Thus, these costs must be recovered in rates in a manner that does not involve ''transmission of electric energy in interstate commerce'' as that phrase is used in the FPA.[227] This approach ensures that the wholesale market will not be burdened by retail costs. It also ensures that one state will not be able to place costs stranded by its ordering of retail wheeling[228] on customers in another state.

As discussed *infra*, we believe the states have a number of mechanisms to provide for recovery of retail stranded costs in retail rates. One of those mechanisms is a surcharge to state-jurisdictional rates for local distribution. Accordingly, we are proposing to define ''facilities used in local distribution'' under section 201(b) of the FPA.[229] We believe states may impose retail stranded costs on facilities or services falling under this definition.[230]

We set out our preliminary findings here for the limited purpose of reopening the comment period of the Stranded Cost NOPR as to whether the requirements proposed in the Open Access NOPR raise additional implementation or other issues pertaining to stranded cost recovery that were not addressed in the initial Stranded Cost NOPR and, if so, whether the mechanisms we propose based on our preliminary determinations are adequate to allow recovery of stranded costs. Additional issues on which we seek comment are delineated below.

c. The Proposed Regulations. (1) Justification for Allowing Recovery of Stranded Costs and Estimates of the Magnitude of Stranded Costs. (a) *Comments*

Virtually all of the investor-owned utility commenters support the NOPR's basic assumption that stranded costs can be created when a customer switches suppliers. Many commenters, including Electric Generation Association and Public Power Council, applaud the Commission for timely ''addressing the difficult and controversial stranded cost issue and for recognizing that this issue must be resolved in order for all parties to harvest fully the benefits of a competitive electric industry.'' [231] Edison Electric Institute (EEI) strongly endorses the recovery of stranded costs.

A number of commenters, primarily representing customer groups, disagree that the risk that a utility could lose customers (and thereby incur stranded costs) is a new phenomenon created by regulatory and statutory initiatives that utilities could not anticipate. These commenters argue that utilities have long been aware that they risk losing customers to competition and that utilities should have planned for this eventuality.

In support of this argument, American Forest and Paper Association (American Forest) and others argue that utilities have known for some time that wholesale customers can—and in the

subject to this Commission's jurisdiction. Nevertheless, we do encourage such a transmitting utility to attempt to negotiate a mutually agreeable stranded cost amendment with its customer. In addition, we will allow such a transmitting utility to file a request to recover stranded costs in transmission rates under FPA sections 211–212. However, such transmitting utility would be required to make the same evidentiary demonstration as that required of public utilities seeking extra-contractual stranded cost recovery.

[225] The customer's maximum possible stranded cost exposure without mitigation would be the revenues that the utility would have received from the customer had the customer continued to take service from the utility. This is the amount from which the competitive market value of the power that the customer would have purchased would be deducted to compute the amount of recoverable stranded costs (using the ''revenues lost'' approach for calculating stranded costs that this rule proposes to adopt (see section III.F.1.c(8) infra)). The utility will be required to make every effort to mitigate the amount of the stranded cost charge. See section III.F.1.c(9).

[226] Although the Commission's June 29 NOPR characterized these types of stranded costs as ''retail'' stranded costs, we believe they are more appropriately characterized as ''wholesale'' stranded costs, since it is not only state or local authority that permits the costs to be stranded, but also the availability of wholesale transmission that causes the costs to be stranded.

[227] See 16 U.S.C. § 824(c).

[228] We do not address whether states have the lawful authority to order retail wheeling in interstate commerce.

[229] 16 U.S.C. 824(b).

[230] States may also use their jurisdiction over local distribution facilities to address potential ''stranded benefits,'' *e.g.*, environmental benefits associated with conservation, load management, and other demand side management (DSM) programs. See NARUC Resolution on Competition, the Public Interest, and Potentially Stranded Benefits, November 16, 1994 (Appendix C to NARUC's comments).

[231] Electric Generation Association comments at 1.

general course of business, in fact, do—leave utilities' systems for other suppliers without being obligated to pay for stranded costs. Several commenters also argue that Congress put the industry on notice through PURPA and then EPAct that utilities are at risk of losing customers as a result of the pro-competitive provisions of these statutes. Numerous parties[232] note that the courts and the Commission have, in various cases, provided notice that, as a result of competitive forces in the industry, utilities have had no reasonable expectation that customers will remain on their systems after contract expiration. Commenters cite, among other cases, the Supreme Court's 1973 decision in *Otter Tail*[233] (in which the Court held that the refusal to wheel power could place a utility at risk of antitrust liability), the Commission's 1968 decision in *Village of Elbow Lake* v. *Otter Tail Power Company*[234] (in which utilities were alerted to the threat of municipalization), and the Commission's 1983 decision in *Kentucky Utilities Co.*[235] (in which a notice of termination provision was deemed to constitute the extent of the utility's protection of its investment incurred to support the contract service).

Some commenters[236] argue that the Stranded Cost NOPR incorrectly assumes the existence of a wholesale service obligation. These commenters argue that the NOPR improperly assumes that a utility has had an obligation to serve a wholesale requirements customer beyond the term set forth in the contract unless the contract contained a notice of termination provision or other more explicit stranded cost provisions. According to these commenters, the wholesale service obligation is purely contractual, and utilities could not reasonably have expected to continue to provide service after the expiration of a particular contract.

Some state commissions (*e.g.*, Illinois Commission) also find the NOPR's notion of wholesale stranded costs to be misplaced. These state commission commenters note that competition and notice provisions have existed for decades and that a customer leaving the system for another supplier is no different from a customer leaving due to an economic downturn (*e.g.*, a plant closing or relocation). Under the latter circumstance, they note that the costs are allocated among the remaining customers, or, in some instances, shareholders. A number of other state commissions (*e.g.*, Indiana Utility Regulatory Commission (Indiana Commission)) urge that stranded cost recovery exclude costs associated with normal business risk, such as poor planning, customer relocation, self-generation, or cogeneration.

With regard to the magnitude of the level of total industry stranded costs, while estimates vary widely, most commenters agree that the level of potential wholesale stranded costs is small relative to that of retail stranded costs. Several state commissions and customer groups (*e.g.*, Florida Public Service Commission (Florida Commission), APPA, Industrial Consumers, Illinois Commission, and SCOOP) argue that the potential level of wholesale stranded costs is largely exaggerated. For example, SCOOP claims that ''[s]eparating out only the wholesale exposure to stranded costs, and critically analyzing the extent of that exposure, will permit the Commission to recognize that wholesale stranded costs are little more than the 'flea on the tail of the dog' and not the dog itself.''[237] Many of these commenters, including the Illinois Commission, note that wholesale stranded costs are likely to be minimal because wholesale requirements sales for major investor-owned utilities account for roughly 6 percent of their total net energy generated and received. Furthermore, these commenters contend that it is ridiculous to suggest that all of the generation assets associated with serving this wholesale load suddenly would become stranded. In fact, some commenters expect the investor-owned utilities with lower-cost generation to benefit from increased competition.

Additionally, the Environmental Action Foundation (Environmental Action) notes that some industry estimates assume a zero asset (or salvage) value for any stranded assets. Environmental Action claims that this assumption grossly overestimates the claimed industry level of stranded costs by failing to recognize that a utility with a stranded generating asset will likely lower its power prices to market levels to mitigate the total level of stranded costs. Accordingly, Environmental Action suggests that estimated levels of potential wholesale stranded costs may, in fact, be lower after accounting for costs recovered by the utility as a result of aggressively marketing any stranded generating assets.

EEI indicates that, based on an informal survey of its members, the number of cases likely to be filed at the Commission seeking to recover stranded costs from wholesale requirements customers under existing contracts will be far less than those filed during restructuring of the natural gas pipeline industry.[238] However, EEI states that, while the number of filings may be relatively small, the dollar amounts and the significance to the parties are great. EEI indicates that the magnitude of potential wholesale and retail stranded cost liability to the industry is in the upper range of the NOPR's tens of billions of dollars to $200 billion estimate.

(b) Preliminary Findings. The electric utility industry has billions of dollars invested in utility assets and contracts that, in today's markets, may become uneconomic.[239] If wholesale or retail customers leave their utilities' systems without paying a share of these costs, the costs will become stranded unless they can be recovered either from the departing customers or other customers. These are very real costs that, as previously discussed, were incurred under a regulatory system that imposed an obligation to serve on utilities (an explicit obligation at retail and arguably an implicit obligation at wholesale)[240]

[232] *E.g.*, American Power Association (APPA), Florida Municipal Power Agency, Michigan Municipal Cooperative Group and Wolverine Power Supply Cooperative (Florida and Michigan Municipals), the Illinois Commerce Commission (Illinois Commission), Electricity Consumers Resource Council, the American Iron and Steel Institute an the Chemical Manufacturers Association (Industrial Consumers), and TDU Customers.

[233] See *Otter Tail*, *supra* note 15.

[234] *Village of Elbow Lake* v. *Otter Tail Power Company*, 40 FPC 1262 (1968).

[235] Kentucky Utilities Co., Opinion No. 169, 23 FERC § 61,317, *aff'd on reh'g in relevant part*, 25 FERC § 61.205 (1983), *reversed on other grounds*, 766 F.2d 239 (6th Cir. 1985).

[236] *E.g.*, American Forest, Industrial Consumers, the Municipal Resale Service Customers of Ohio, and the Stranded Cost Order Opponent Parties (SCOOP). SCOOP consists of Delaware Municipal Electric Corporation, Village of Freeport, New York, City of Jamestown, New York, Town of Massena, New York, Modesto Irrigation District, M–S–R Public Power Agency, City of Santa Clara, California, and Southern Maryland Electric Cooperative, Inc.

[237] SCOOP comments at 2.

[238] For example, a number of utilities (*e.g.*, Allegheny Power Service Corporation (Allegheny Power), Consumers Power Company, and Wisconsin Power & Light Company (Wisconsin Power)) indicate that their total potential wholesale exposure is minimal.

[239] As discussed in section III.C.2 *supra*, new generation facilities can produce power on the grid at a cost of 3 to 5 cents per kWh, yet the costs for large plants constructed and installed over the last decade were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents per kWh for nuclear plants.

[240] The Commission has never determined whether there is an actual obligation in the FPA to serve requirements customers. Construction Work In Progress, Order No. 474, III FERC Stats. & Regs. ¶ 30,751 at 30,718 (1987). The Commission's regulations, however, do require a rate filing to terminate a jurisdictional contract. 18 C.F.R. § 35.15 (1994). Moreover, in a few cases, the Commission has required service beyond the contract term. *E.g.*,

and also permits recovery of all prudently incurred costs. Moreover, while we recognize that there has always been some risk of a utility losing a customer, that risk has been greatly increased by significant statutory, regulatory, technological, and structural changes, including this rule, that utilities may not have reasonably foreseen at the time their investments were made.

As discussed in the introduction of this document, the wholesale bulk power segment of the electric industry is undergoing a fundamental transformation from a monopolistic industry regulated on a cost-of-service basis to an open access, competitively priced industry. The transformation will accelerate if the Commission adopts the open access transmission requirements it is proposing in Docket No. RM95–8–000. We do not believe that utilities that made large capital expenditures or long-term contractual commitments to buy power many years ago should now be held responsible for failing to foresee such fundamental changes in the industry. The Commission will not ignore the effects of regulatory and statutory changes on the past investment decisions of utilities. We believe that equity requires that utilities have an opportunity to recover legitimate and verifiable stranded costs associated with the development of competitive wholesale markets.

This belief is bolstered by our experience during the restructuring of the natural gas industry. During the 1980s and early 1990s, the Commission undertook a series of actions that eventually led to the restructuring of the gas pipeline industry. The restructuring of the industry and the introduction of competitive forces in the gas supply market left many pipelines holding uneconomic take-or-pay contracts with gas producers.[241]

In Order No. 436, the Commission declined to take direct action to alleviate the burden that the uneconomic take-or-pay contracts placed on pipelines. The Commission based its decision on a number of considerations, including its concern ''regarding the ability of private parties in the gas production industry to rely on private contracts as a tool for structuring basic economic relationships.'' [242]

However, in *AGD,* the U.S. Court of Appeals for the District of Columbia Circuit noted that the pipelines were ''caught in an unusual transition'' as a result of regulatory changes beyond the pipelines' control.[243] The court faulted the Commission for failing to take direct action to address the effect of such regulatory changes on the uneconomic take-or-pay contracts.[244]

The court's reasoning in *AGD* concerning the restructuring of the gas industry is also applicable to the current move to competitive bulk power markets in the electric industry. Once again, a regulated industry is faced with an ''unusual transition'' to a more competitive market. Once again, one result of the transition is the possibility that utilities will be left with large unrecoverable costs. In these circumstances, we believe that we must directly address the costs of the transition to a competitive industry by allowing utilities to recover their legitimate and verifiable stranded costs, and that we must do so simultaneously with any final rule we adopt concerning open access transmission.

(2) The D.C. Circuit Court of Appeals Decision in *Cajun Electric Power Cooperative, Inc.* v. *FERC.* In the *Cajun* case,[245] the D.C. Circuit found that the Commission should have held an evidentiary hearing to determine whether the recovery of stranded investment costs, as permitted in an open access transmission tariff approved by the Commission, was anticompetitive and would preclude mitigation of Entergy Corporation's (Entergy) market power. The transmission tariff under review in that case was intended to mitigate Entergy's market power by providing open access to its transmission system.[246] The open access transmission tariff provided that Entergy's subsidiaries could seek to recover their stranded investments from a departing generation customer by including in the departing customer's transmission rate the cost of Entergy's generation capacity that was stranded when the former customer switched suppliers. The court expressed concern that this provision might constitute a tying arrangement whose purpose is to ''cabin'' Entergy's market power, stating: ''If a company can charge a former customer for the fixed costs of its product whether or not the customer wants that product, and can tie this cost to the delivery of a bottleneck monopoly product that the customer must purchase, the products are as effectively tied as they would be in a traditional tying arrangement.'' [247]

The court noted that central to the Commission's approval of Entergy's open access transmission tariff was the Commission's finding that Entergy's market power would be mitigated upon the implementation of the tariff. [248] However, the court suggested that permitting a transmission monopolist such as Entergy to impose generation-related charges on competitors who only seek transmission services might serve to increase, not mitigate, Entergy's market power because ''Entergy can compete for generation sales outside its transmission grid without concern for a stranded investment charge [but] Entergy's competitors cannot compete for the customers on its transmission system on the same basis.'' [249] Thus, the court held that ''[t]he Commission must address whether the [transmission tariff's] provision of a process for recovery of stranded investment costs * * * precludes genuine open access to Entergy's transmission system. In short, the question that must be asked now is whether the [transmission tariff] allows for 'meaningful access to alternative suppliers.' '' [250] The court went on to identify other provisions of the transmission tariff (in addition to the stranded cost provision) that might lessen the mitigation of Entergy's market power, including Entergy's retention of sole discretion to determine the amount of transmission capability available for its competitors' use; the point-to-point service limitation; the failure to impose reasonable time limits on Entergy's response to requests for transmission service; and Entergy's reservation of the right to cancel service in certain instances even where a customer has

Tapoco, Inc., *et al.*, 39 FERC ¶ 61,363 (1987); Florida Power & Light Company, 8 FERC ¶ 61,121, *reh'g denied*, 9 FERC ¶ 61,015 (1979)).

[241] The costs of gas supply contracts in the gas industry can be viewed as somewhat analogous to the costs of generation resources in the electric industry.

[242] Order No. 436, *supra* note 12 at 31,492–93; see also *AGD*, *supra* note 9, 824 F.2d at 1026.

[243] 824 F.2d at 1027.

[244] *Id.* at 1021.

[245] *Cajun Electric Power Cooperative, Inc.* v. *FERC,* 28 F.3d 173 (D.C. Cir. 1994) (*Cajun*).

[246] The two other electric power tariffs under review in that case provided for the sale of wholesale power by various Entergy public utility subsidiaries at negotiated, market-based rates. As the court indicated, these tariffs, in combination with the open access transmission tariff, ''were designed to permit Entergy—a monopolist of transmission services in the relevant market—to engage in market-based pricing in the generation market, while simultaneously introducing competition to that market through the unbundling of generation sales from transmission services.'' *Id.* at 175.

[247] *Id.* at 178.

[248] The court noted that although the Commission suggested that the stranded investment provision is necessary to lure Entergy into competition and provides an equitable recovery of costs from the parties for whom the costs were incurred, this is irrelevant if the Entergy tariffs do not sufficiently mitigate Entergy's market power. *Id.* at 180.

[249] *Id.*

[250] *Id.* at 179 (emphasis in original).

paid for transmission system modifications.[251]

The court concluded that the transmission tariff as a whole ''seems to provide Entergy with the means to stifle the very competition it purports to create.'' [252] The court determined that the Commission erred in approving Entergy's tariffs without conducting hearings on whether, notwithstanding the purpose of the transmission tariff to mitigate market power, Entergy might retain market power. Significantly, however, the court did not hold that stranded cost recovery could not be justified; its objection was to the Commission's procedures in that particular case and lack of explanation for its substantive decision to approve the stranded cost provision.

(a) Comments. Most customer groups and many state representatives (e.g., APPA, Blue Ridge,[253] National Association of Regulatory Utility Commissioners (NARUC) and the Vermont Department of Public Service (Vermont Department)) contend that the *Cajun* decision either prevents the Commission from allowing the recovery of stranded costs through transmission charges, or, at best, raises questions concerning the scope of the Commission's legal authority to do so. In light of *Cajun,* some commenters, such as the National Rural Electric Cooperative Association (NRECA), urge the Commission to terminate the NOPR.

Environmental Action contends that a transmission adder does not by itself constitute tying or leveraging. It submits that if the transmission adder consists of costs that a customer is obligated to pay in any event, the adder merely holds the customer to its existing bargain. Environmental Action argues that in *Cajun,* however, the transmission adder was not being used to recover costs for which the transmission customer was already obligated, but had the effect of penalizing the customer for entering into a new obligation. According to Environmental Action, the NOPR ''makes the same error'' to the extent that the costs proposed to be recovered in the transmission adder are not part of the contractual quid pro quo.[254]

All of the investor-owned utility commenters, except Wisconsin Power & Light Company (Wisconsin Power), argue that the *Cajun* decision is not a bar to recovery of stranded costs through transmission rates.[255] These commenters (e.g., EEI and Duke) argue that the *Cajun* decision was based on procedural grounds and merely stands for the proposition that the Commission should have held an evidentiary hearing in that case to resolve anticompetitive concerns. These commenters also argue that the portion of the *Cajun* decision relied on by the customer commenters is only *dictum.*

Some commenters further contend that allowing the recovery of stranded costs through a transmission surcharge does not constitute an unlawful tying arrangement. EEI notes, as an initial matter, that the courts no longer view every bundling of products or services as a tying arrangement that is *per se* unlawful under the antitrust laws. Moreover, EEI submits that in a tie-in, a seller of one product requires its purchasers to buy the tied product by bundling the products together to promote sales in related markets that it could not achieve under competitive circumstances, effectively foreclosing the purchaser from obtaining the second product from competitors even if it could do so at a lower cost. EEI argues that a stranded cost surcharge, in contrast, would include only part of the former price of the power (the mark-up above its marginal cost included in the price approved by regulators), and would thereby allow the purchaser to obtain bulk power from competitive suppliers with the lowest marginal costs.

With regard to the potential anticompetitive effects of allowing stranded cost recovery, some commenters contend that stranded cost recovery would inhibit the movement toward competition, distort price signals, result in inefficient decisionmaking, and unfairly reward the least efficient utilities.

For example, APPA argues that charges for stranded costs are anticompetitive and hinder the development of a competitive market by, among other things: (1) Distorting transmission prices and erecting artificial barriers to new suppliers; (2) giving the host utility a paid-off asset with which to compete unfairly; and (3) slowing the introduction of new technology. APPA argues that the disallowance of stranded costs would encourage all utilities to strive for greater efficiencies and to compete for sales on the basis of price and service.

The Ad Hoc Coalition on Environmental and Consumer Protection (Ad Hoc Coalition) argues that stranded cost recovery will amount to a government-ordered subsidy for electric generation from older, less efficient units that will further environmental degradation and stifle the move toward greater competition. It claims that the stranded costs that utilities primarily will be seeking to recover are uneconomical nuclear generation assets, and that the NOPR thus offers a new subsidy for nuclear power by shifting cost responsibility for nuclear assets from shareholders to ratepayers. The Ad Hoc Coalition believes that such a subsidy could affect investment decisions for the next generation of nuclear power plants if investors believe that they will be allowed to recover their costs as long as a ''reasonable expectation'' existed at the time the decision to build was made. Thus, the Ad Hoc Coalition argues that the NOPR will send an improper signal to utility managers and investors that generation investments remain safe investments, even when they do not pass the tests of a competitive market. According to the Ad Hoc Coalition, such a policy perpetuates the continued reliance on older, less efficient generating units that harm the environment.

American Forest asserts that blanket assurances of stranded cost recovery are anticompetitive and create no incentive for utilities to lower their operating costs and mitigate any uneconomic costs. According to American Forest, stranded costs create enormous uncertainty that may make financing of competitors' plants impossible at any cost, thus killing the very competitive market the Commission seeks to foster.

The Illinois Commission believes that stranded cost recovery produces an incorrect competitive result because such action effectively ''props up'' the least efficient (high-cost and high-price) utilities. The Illinois Commission argues that stranded cost recovery mechanisms effectively punish the more efficient suppliers that have paid attention to changing realities and have assumed a more competitive market-sensitive posture.

In sharp contrast to the commenters that argue stranded cost recovery would hinder competition, commenters such as EEI, the United States Department of Energy (DOE), the Coalition for Economic Competition,[256] and the

[251] *Id.* at 179–80.

[252] *Id.* at 180.

[253] Blue Ridge consists of Blue Ridge Power Agency, Northeast Texas Electric Cooperative, Sam Rayburn G & T Electric Cooperative and Tex-La Electric Cooperative.

[254] Environmental Action comments at 79.

[255] Wisconsin Power argues that stranded costs should be recovered, but not through transmission rates.

[256] The Coalition for Economic Competition consists of the following New York investor-owned utilities: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk

Conservation Law Foundation (CLF)[257] contend that stranded cost recovery can promote a quicker transition to competition and can be used to enhance efficiency. Some commenters (*e.g.,* DOE, Industrial Consumers, Enron Power Marketing, Inc. (Enron), CLF, and the Competitive Electric Market Working Group (Competitive Working Group)[258]) suggest linking the recovery of stranded costs to utility actions that will further wholesale competition, such as the filing of an open access transmission tariff or membership in a regional transmission group (RTG).

Commenters representing the financial community (e.g., Utility Investors and Analysts, American Society of Utility Investors, United Utility Shareholders Association of America) strongly support recovery of stranded costs so that the financial stability of the electric utility industry will be protected. These commenters argue that the amount of potential stranded costs exceeds the amount of equity investment in electric utilities. According to these commenters, investors have not made their current investment decisions with the rigors of competition in mind, nor have rate of return hearings included testimony concerning competitive risk. Without full recovery of stranded costs, financial community commenters argue, financial integrity will deteriorate, and utilities will be unable to attract capital. Due to the capital-intensive nature of the electric utility industry, these commenters note that lack of access to capital markets at reasonable rates will prevent utilities from keeping costs down.

(b) Preliminary Findings. We do not interpret the *Cajun* court decision as barring the recovery of stranded costs. Rather, the *Cajun* court remanded the case because the Commission failed to hold an evidentiary hearing concerning whether the inclusion of a stranded cost recovery provision in Entergy's transmission tariff precluded the mitigation of Entergy's market power. As previously discussed, the court also found the Commission's substantive decision flawed because the Commission failed to explain adequately its approval of the stranded cost provision, among others. In this consolidated proceeding (*i.e.,* the Stranded Cost NOPR, the Supplemental Stranded Cost NOPR, and the Open Access NOPR), we are providing the evidentiary record for addressing all of the court's concerns on a generic basis, and the opportunity for all participants in the electric industry to present evidence and arguments. We are also providing a full explanation of why the recovery of legitimate stranded costs is critical to the successful transition of the electric utility industry from a tightly regulated, cost-of-service industry to an open transmission access, competitive industry that will drive down the prices of electricity to consumers.

The court in *Cajun* was concerned about whether Entergy's tariff allowed ''meaningful'' access to alternative suppliers. In this regard, the court stated that the Commission must address not only whether the stranded cost provision allowed for meaningful access, but also whether other provisions in the tariff might lessen the utility's market power. In the Open Access NOPR, the Commission is attempting to mitigate the core of market power not only for Entergy, but for all traditional public utilities: control over transmission access. The Commission is generically addressing all aspects of transmission market power, including those specifically identified by the *Cajun* court (*e.g.,* point-to-point service limitations). Indeed, a fundamental purpose of the Open Access NOPR is to ensure the meaningful access to alternative suppliers that was identified by the *Cajun* court.[259] The Open Access NOPR includes the specific terms and conditions of access (contained in the pro-forma tariffs) that we believe are the minimum necessary to mitigate transmission market power.[260] Of utmost importance in mitigating market power is the Commission's non-discrimination (comparability) requirement, a requirement that had not been articulated at the time of the Commission's order under review in *Cajun,* and that is proposed to be codified in the Open Access NOPR proceeding.

With regard to the *Cajun* court's concern about stranded cost provisions, the Commission in *Entergy* failed to articulate the transition that the industry is experiencing, the fundamental fact that full competition is not yet a reality, and that stranded costs are a temporary but serious phenomenon that must be addressed if we are to successfully move from one regulatory regime to another, thereby creating fully competitive bulk power markets. In this regard, the Open Access NOPR provides a detailed explanation of the fundamental industry and regulatory changes that have given rise to the potential for stranded costs. In addition, in the Stranded Cost NOPR and the Supplemental Stranded Cost NOPR, we have gathered (and are continuing to gather) information concerning the magnitude of potential stranded costs; we have provided an explanation of the transitional nature of stranded costs; and we have explained the critical need to deal with these costs in order to reach competitive wholesale markets. We have also explained existing disparities in electricity rates and the consumer benefits that can accrue if we achieve fully competitive markets.[261]

Failure to deal with the stranded cost problem would likely delay and would certainly complicate the transition to fully competitive bulk power markets. For example, stranded costs would then be borne by the utilities' shareholders, which could threaten the stability of the industry and the service it provides, or be reallocated to remaining customers, raising the price to such customers. An additional consideration is the fact that the *AGD* court instructed the Commission that it must consider the transition costs borne by regulated utilities when the Commission changes the regulatory rules of the game.

We conclude that stranded cost recovery as proposed in this rulemaking is not a tying arrangement, as discussed by the *Cajun* court, and that the proposed cost recovery procedure will not ''cabin'' market power.[262] Rather, the stranded cost recovery procedure is

Power Corporation, and Rochester Gas & Electric Company.

[257] CLF is a non-profit environmental law organization that represents approximately 10,000 members in the six New England states.

[258] The Competitive Working Group consists of Electric Clearinghouse, Inc., Enron Power Marketing, Inc., and Destec Power Services, Inc.

[259] See *Cajun,* 28 F.3d at 179.

[260] In seeking comment in the Open Access NOPR on the adequacy of these terms and conditions, we seek specific comment on the terms and conditions that were of concern to the *Cajun* court. See discussion *supra* Section III.E.4. For example, the *Cajun* court expressed concern that the point-to-point service limitation in Entergy's transmission tariff might restrain competition. However, under the Open Access NOPR, service will not be limited to point-to-point. Instead, customers will be allowed to choose between point-to-point and network service.

[261] There is a wide disparity in consumer electricity prices across the United States. Some consumers pay more than 10 cents per kilowatt-hour on average, while others pay about one-third as much. While some of this price disparity is due to regional cost differentials, some of it may also be due to ineffective access to new power supplies. We believe that all consumers will benefit from changes that allow their suppliers greater access to lower-cost power supplies. This greater access can best be achieved by ensuring that non-discriminatory open access transmission service is available to all potential users of the transmission grid. The result will be greater trading opportunities among suppliers, and also more investment opportunities for new entrants in generating markets. All of this should serve the interests of consumers by lowering electricity prices.

[262] *Cajun,* 28 F.3d at 177–78.

being prescribed to enable utilities, during a transitional period, to recover costs prudently incurred under a different regulatory regime.

Finally, the financial community argues strongly and plausibly that recovery of legitimate and verifiable stranded costs at this critical stage in the industry's move toward competition is needed to protect the financial stability of the electric industry. They confirm that the prospect of not recovering stranded costs could erode a utility's ability to attract capital, which, in turn, could impede the long-term goal of achieving competitive wholesale markets.

(3) Responsibility for Wholesale Stranded Costs (Whether to Adopt Direct Assignment to Departing Customers). In the initial NOPR, the Commission proposed to allow utilities to seek to assign stranded costs associated with the departure of a given wholesale customer directly to that departing wholesale customer.[263] We noted, however, that an alternative might be to assign stranded costs more broadly by, for example, requiring all transmission customers (including native load which takes bundled service) to pay a higher rate for use of the transmission system. We invited comments on the direct assignment and alternative methods of stranded cost recovery.[264]

(a) Comments. Many parties (representing all constituencies) support the direct assignment of stranded costs to the departing customer as proposed in the initial NOPR. Most commenters contend that the cost causation principle supports this approach. These parties argue that utilities undertake obligations on a customer's behalf and that, by leaving the system, the departing customer avoids paying for its fair share of these obligations. They further argue that general fairness requires that customers remaining on the system should not have to pay for a departing customer's obligations; they allege that this could lead to more customers leaving the system and the eventual bankruptcy of the utility.

Nevertheless, other commenters suggest a framework for stranded cost recovery that is different from the direct assignment method suggested in the NOPR. According to some commenters (*e.g.*, South Carolina Electric & Gas Company), stranded costs should be allocated to all customers and shareholders because everyone will benefit from the transition to competitive generation markets. In this manner, they contend that the overall burden would be reduced, because stranded costs would be spread among a greater number of parties. Commenters that support spreading the costs to all customers argue that requiring the departing customer to shoulder all stranded costs will result in few customers going off-system due to the economic inefficiency of paying two suppliers. Several commenters (*e.g.*, Indiana Commission, Rhode Island Division of Public Utilities and Carriers, Department of Water and Power of the City of Los Angeles, and Fuel Managers Association) suggest that some shareholder liability for stranded cost recovery should be required, arguing that it would provide utilities with a greater incentive to mitigate stranded costs.

Some commenters support the recovery of stranded costs through a transmission surcharge applicable to all transmission customers.[265]

Other commenters oppose a general surcharge on all transmission customers, arguing that existing transmission customers, including native load, should not be allocated any stranded costs because they did not cause any costs to be stranded in the first place. Washington Water Power Company and Wisconsin Electric Power Company oppose a transmission surcharge on the basis that it makes an otherwise competitive supplier less marketable due to higher wheeling rates. Others allege that a transmission surcharge is inconsistent with the unbundling of transmission service and would slow the restructuring (disaggregation) of vertically-integrated utilities. Thus, according to some commenters, the use of a transmission surcharge would slow the move to competitive markets because the surcharge sends the wrong price signal, involves cross-subsidization by native load, penalizes competitive alternatives, and awards monopoly rents to the utility. Some commenters also note that, where the departing customer does not take transmission service from its former supplier, the departing customer escapes all responsibility for the stranded costs.

Some commenters contend that the *Cajun* decision prohibits the use of a transmission surcharge. Still others argue that generation costs should not be assigned to transmission users because utilities would then have an incentive to shift costs to transmission in order to make their generation more competitive. SCOOP argues that the shifting of generation costs to transmission rates violates the Commission's policy prohibiting costs unrelated to the transmission function from being included in transmission charges.[266]

The Public Utility Commission of Texas (Texas Commission) proposes a hybrid approach whereby a portion of stranded costs would be directly assigned to the departing customer and the remainder allocated through a general surcharge to all wholesale market participants. However, if a general surcharge on transmission customers is adopted, the Texas Commission supports the pooling of all stranded costs and the creation of an industry-wide surcharge. The Texas Commission does not explain how such a pool would be administered.[267]

Commenters that represent shareholder interests (American Society of Utility Investors, United Utility Shareholders Association of America, and Utility Investors and Analysts) argue against allocation of any stranded costs to shareholders because the rates of return granted to utilities in the past have not included any compensation for the risk of competition. They submit that fairness dictates that those placed at risk by a sudden change in the rules not be penalized. Tennessee Valley Authority (TVA), which as a Federal corporation has no shareholders to absorb stranded costs, shares this view.

(b) Preliminary Findings. After careful consideration of the various comments, we believe that direct assignment of stranded costs to the departing wholesale customer, as proposed in the initial NOPR, is the appropriate method for recovery of such costs.[268] This method is consistent with the cost

[263] Methods of direct assignment include a lump sum payable when the customer leaves the system. Such an exit fee could also be recovered over time in monthly installments. Presumably the utility would charge interest on the unamortized balance if the customer selected a delayed payment approach.

[264] Stranded Cost NOPR at 32,867–68.

[265] Some commenters (*e.g.*, Allegheny Power) distinguish between transmission surcharges imposed on transmission-only customers as opposed to all customers. In the former case, only those customers taking transmission-only service from the utility would be assessed stranded costs; customers taking bundled service would not be assessed such costs. Allegheny Power indicates that it would support such an approach only if the Commission decides not to fully assign stranded costs to departing customers.

[266] SCOOP comments at 38 (citing Northern States Power Company, Opinion No. 383, 64 FERC ¶ 61,324 at 63,377 (1993)).

[267] Trigen Energy Corporation advocates that Congress impose a "sunset" energy tax on all electricity used in order to pay off stranded costs.

[268] Because we are also proposing to entertain requests for recovery of stranded costs attributable to retail-turned-wholesale wheeling customers, or to retail wheeling customers in certain limited circumstances, our determinations and rationale regarding direct assignment also apply to those situations.

causation principle.[269] As discussed in greater detail below, as part of the evidentiary demonstration necessary for stranded cost recovery associated with certain departing wholesale requirements customers,[270] retail-turned-wholesale transmission customers, or unbundled retail transmission customers, a utility must show that the costs are not more than the customer would have contributed to the utility had the customer continued to take generation service from that utility. We believe it only appropriate that the departing customer, and not the remaining customers (or shareholders), bear its fair share of the legitimate and prudent obligations that the utility undertook on that customer's behalf.

The Commission recognizes that the direct assignment approach for addressing stranded costs for the electric industry differs from the approach eventually taken for the natural gas industry. In Order No. 636, which involved the restructuring of the gas industry, the Commission determined that it was appropriate to spread the majority of the remaining transition costs associated with take-or-pay and other contracts to all customers (existing and new) using the interstate natural gas transportation system.[271] However, unlike the situation facing the electric utility industry today, by the time the Commission issued Order No. 636, changes in the natural gas industry had progressed to such a point that it was not possible for the Commission to use a strict cost causation approach. Many natural gas customers had already left their historical pipeline suppliers' systems. Others had converted from sales and transportation customers to transportation-only customers. Others were in a transition stage having had opportunities to lower their contract demands or otherwise become partial service customers. Significant take-or-pay and other costs had accumulated. In contrast, in the electric area, the Commission (and the states) will be better able to address the transition cost issue up front, and to address stranded cost recovery *before* customers leave their suppliers' systems. This, in effect, will prevent the accumulation of unrecovered costs and will comport with our past policy of assigning costs to customers who caused the costs to be incurred.

In addition, allowing direct assignment of stranded costs will ensure that there are no stranded costs left to be borne by the remaining customer base or by the shareholders. This, in turn, will ensure that the financial health of the industry is not placed in jeopardy. If some customers are permitted to leave their suppliers without paying for costs incurred to serve them, this may cause an excessive burden on the remaining customers (such as residentials) who cannot leave and therefore may have to bear those costs. Moreover, the prospect or lack thereof for recovering such costs from ratepayers could erode a utility's access to capital markets or significantly increase the utility's cost of capital. This higher cost of capital could precipitate other customers leaving the system which, in turn, could cause others to leave. Such a spiral could be difficult to stop once begun.

The alternatives to direct assignment of stranded costs are to do nothing or to assess stranded costs more broadly through some type of general surcharge on all customers. As discussed above, to do nothing would mean that the Commission would have to reallocate stranded costs to shareholders or to remaining customers. Those customers that caused the costs to be stranded would not have to pay. This would violate the cost causation principle which has been fundamental to the Commission's regulation since 1935. The other alternative, to assess costs more broadly, also violates this principle. Moreover, there appears to be no strong countervailing reason to assess costs broadly in the electric utility industry.

(4) Recovery of Stranded Costs Associated With New Wholesale Power Sales Contracts. The NOPR proposed that public utilities and transmitting utilities would not be permitted to seek extra-contractual recovery of stranded costs associated with ''new'' contracts, *i.e.*, contracts executed after July 11, 1994, through transmission rates for section 205 or 211 transmission services. For new contracts, the NOPR proposed that stranded cost recovery would be allowed only if explicit stranded cost provisions are contained in the contract accepted by the Commission.[272] We also stated our preliminary view that it is not appropriate in this new regime to impose on wholesale requirements suppliers any regulatory obligation to continue to serve their existing requirements customers beyond the end of the contract term. However, we invited comment on the extent to which there should be such an obligation. We also sought comment concerning whether section 35.15 of the Commission's regulations, concerning notice of termination, should be deleted.

(a) Comments. Some of the commenters dispute the Commission's belief that there should not be a future regulatory obligation to continue to serve wholesale requirements customers beyond the end of the contract. SCOOP argues that the FPA imposes an obligation on a public utility to continue wholesale service beyond the term of the contract when such service is required by the public interest, and that the Commission does not have the power to abrogate this authority. Sunflower Electric Power Corporation (Sunflower) submits that, for stability reasons, a utility's obligation to serve requirements customers should run beyond the end of the contract term.

Some commenters (*e.g.*, SCOOP, Sunflower, Illinois Commission) generally support Commission retention of its section 35.15 notice of termination filing requirement, arguing that such filing requirement is reasonable and/or necessary to ensure that any termination in service is not contrary to the public interest.

Other commenters support the Commission's position that there should not be a future regulatory obligation to continue to serve wholesale requirements customers beyond the end of the contract and support modification or elimination of section 35.15. These

[269] Contrary to arguments made by SCOOP, the shifting of generation costs to transmission rates does not violate Commission policy. The *Northern States* case cited by SCOOP deals with the Commission's bright line functionalization policy, pursuant to which the Commission, largely as a matter of administrative convenience, has attempted to maintain a boundary between generation and transmission functions. In that case, we found that refunctionalization is not *per se* improper or contrary to Commission policy, and we suggested that strict application of the traditional bright line approach may need to be reexamined in light of changes taking place in the electric industry. 64 FERC at 63,379. Significantly, we stated that the ''*fundamental* theory of Commission ratemaking is that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the costs to be incurred.'' *Id.* (emphasis in original).

This is exactly what we propose to do in the Stranded Cost NOPR and the Supplemental Stranded Cost NOPR. The customer that caused the costs to be incurred and stranded will continue to pay the costs. The only difference is that in some instances the customer will pay the costs through an adder to its transmission rate instead of through a generation rate.

[270] *I.e.*, departing wholesale requirements customers under contracts entered into on or before July 11, 1994, who will use the utility's transmission system to reach other suppliers and whose contracts do not explicitly address stranded costs.

[271] Order No. 636 at 30,457–62.

[272] Under the proposed regulations, a public utility may seek recovery of such costs in accordance with the contract. However, if wholesale stranded costs are associated with a new wholesale requirements contract and the seller under the contract is a transmitting utility but not also a public utility, the transmitting utility may not seek an order from the Commission allowing recovery of such costs. See Stranded Cost NOPR at 32,882.

commenters argue that if contracts are to govern future requirements relationships in the electric industry, the Commission should allow the contracts to terminate on their own terms, without the need for a filing and Commission approval. New England Power Company submits that continuation of such a filing requirement would add uncertainty to the parties' mutually agreed upon termination date and, in turn, promote inequitable and asymmetrical risk/ benefit allocations and ineffective resource planning. EEI asks the Commission to make a finding that it is in the public interest to end the regulation of the termination of bulk power contracts. EEI suggests that the Commission could (1) grant a blanket waiver of the regulations requiring notice of termination for new contracts; (2) amend section 35.15 to pre-grant waiver of notice of termination; or (3) amend the regulations to pre-grant waiver of notice of termination in all bulk power contracts signed after the Commission makes its public interest finding to end the regulation of contract terminations.

(b) Preliminary Findings. The Commission believes that future wholesale contracts should explicitly address the mutual obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. Now that utilities have been placed on explicit notice that the risk of losing customers through increased wholesale competition must be addressed through contractual means only, they must address stranded cost issues when negotiating new contracts or be held strictly accountable for the failure to do so. Accordingly, public utilities and transmitting utilities will be allowed stranded cost recovery associated with new contracts (executed after July 11, 1994) only if explicit stranded cost provisions are contained in the contract. Recovery of wholesale stranded costs associated with any new requirements contract (executed after July 11, 1994) will not be allowed unless such recovery is provided for in the contract.

Further, to ensure that the rights and obligations of sellers and buyers are symmetrical in the new competitive era, we do not believe that it is appropriate to impose on wholesale requirements suppliers a regulatory obligation to continue to serve their existing requirements customers beyond the end of the contract term. A requirements customer thus will be responsible for planning to meet its power needs beyond the end of the contract term. In this regard, it may sign a new contract with its existing supplier, or it may contract with new suppliers in conjunction with obtaining transmission service under its existing supplier's open access transmission tariff.

We believe that the section 35.15 filing requirement should be retained for all contracts required to be filed under sections 205 and 206 of the FPA that were executed prior to the effective date of the generic tariffs that we discuss herein.[273] With regard to any power sale contract executed on or after that date,[274] we propose to no longer require prior notice of termination pursuant to the provisions of section 35.15. However, for administrative reasons, we will require written notification of the termination of such contract within 30 days after the date termination takes place.

(5) Recovery of Stranded Costs Associated With Existing Wholesale Power Sales Contracts. In the initial Stranded Cost NOPR (and again in this Supplemental NOPR) we stated that stranded costs are a transitional problem and that neglecting their recovery could delay the realization of fully competitive bulk power markets. We stated that it is thus important to set a date beyond which the Commission will no longer permit extra-contractual recovery of stranded costs that result from existing requirements contracts. To that end, we proposed a three-year transition period during which public utilities must attempt and non-public utilities are encouraged to attempt to renegotiate certain existing wholesale requirements contracts (*i.e.*, those that do not explicitly address stranded costs through an exit fee or other stranded cost provision), and during which they may seek recovery of stranded costs. However, if an existing wholesale requirements contract explicitly addresses stranded costs through an exit fee or other stranded cost provision, the initial NOPR would require the utility to recover such costs only as specified in the contract; it would not permit unilateral filings to change stranded cost provisions and would not permit the utility to seek recovery through transmission rates of stranded costs associated with that contract. Under the initial NOPR, existing contracts that prohibit stranded cost recovery, or explicitly prohibit renegotiation of an existing stranded cost or exit fee provision, or that prohibit renegotiation until after the three-year period has expired would not be subject to the obligation to renegotiate.[275]

Where an existing contract does not contain a stranded cost provision and the parties to the contract are unable to negotiate a stranded cost amendment, and the selling utility is a public utility, the initial NOPR proposed to permit the public utility to unilaterally file under section 205 or 206 of the FPA prior to the end of the three-year period a proposed stranded cost provision as an amendment to the existing contract. The NOPR also proposed to permit the selling public or transmitting utility to seek to recover stranded costs through jurisdictional transmission rates if, prior to the end of the three-year transition period, the customer under the existing wholesale requirements contract gives notice pursuant to the contract that it will no longer purchase all or part of its requirements from the selling utility, but instead will purchase unbundled section 205 or section 211 transmission services from the selling utility that will begin prior to the end of the three-year period.

Under the initial NOPR, if a contract does not include an exit fee or other explicit stranded cost provision, but does contain a notice provision, the Commission proposed that there be a rebuttable presumption that the selling utility had no reasonable expectation of continuing to serve the customer beyond the period provided in the notice provision. We proposed to apply such presumption when the public utility proposed a unilateral amendment to the contract to change the notice provision and/or add an exit fee provision, or if the public utility or transmitting utility sought stranded cost recovery through transmission rates.[276]

The Commission recognized that some utilities' existing contracts may not provide for unilateral rate changes. We noted that although under the *Mobile-Sierra* doctrine[277] a customer may waive its right to challenge the contract and/or the utility may waive its right to make unilateral rate changes, the parties may not waive the indefeasible right of the Commission to alter rates that are contrary to the public interest. We went on to explain why we believe that it is in the public interest to permit public utilities with *Mobile-Sierra* contracts a limited opportunity to

[273] We also propose to retain the section 35.15 filing requirement for any unexecuted contracts that were filed prior to the effective date of the generic tariffs proposed herein.

[274] We request comments on whether this proposal should also be applied to transmission contracts.

[275] The parties, of course, could always voluntarily renegotiate the contract.

[276] Stranded Cost NOPR at 32,861; 32,869–70.

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

propose contract changes unilaterally to address stranded costs if their contracts do not already explicitly do so.

In the NOPR, the Commission invited comments regarding, among other things, whether there should be a transition period during which utilities may renegotiate existing contracts, the appropriate length for such a transition period, whether utilities or customers with contracts that do not provide for unilateral amendments should be able to make unilateral filings or file complaints, whether the Commission should make a *Mobile-Sierra* public interest finding based on company-specific findings instead of generic industry-wide findings, the types of contractual provisions that might demonstrate a sufficient meeting of the minds between the parties so that requiring renegotiation would be inappropriate, whether to apply the rules regarding existing contracts only to contracts between unaffiliated entities, and whether the rebuttable presumption should also be applied to any contract entered into after the date of enactment of the Energy Policy Act, even though the contract does not contain an exit fee or other explicit stranded cost provision or a notice provision.

(a) Comments. (i) Contract Renegotiation. Investor-owned utilities, EEI, and the majority of state commissions generally favor renegotiation of requirements contracts.[278] These commenters argue that the transition to a competitive market should not preclude utilities from recovering costs prudently incurred to serve customers who may wish to leave the system that was planned and built to serve the customers' needs.

Commenters representing cooperatives, municipal, industrial customers, and independent power producers generally oppose renegotiation. These commenters suggest that the framework established in the NOPR, requiring good faith renegotiation of contracts and permitting the unilateral filing of revised contracts to provide for recovery of stranded costs (where renegotiation fails), will result in a violation of the *Mobile-Sierra* doctrine. Numerous commenters argue that contracts should stand on their own, and that there is no factual record upon which the Commission can make a generic public interest finding, as required by *Mobile-Sierra*, that contracts should be modified. These commenters maintain that ''assumed'' threats to the financial stability of the industry do not meet the extremely heavy *Mobile-Sierra* burden of proof that is required to release a public utility from a contract. They argue that it is not the Commission's place to relieve utilities of improvident bargains. Many customer group commenters argue that requiring contract renegotiation improperly shifts the burden of proof from the utility to the customer. These commenters further argue that permitting contract renegotiation implies that customers should pay for a utility's failure to protect itself from business risk.

Some commenters, such as American Forest, argue that the NOPR would, in essence, rewrite the law of contracts. These commenters state that there is no legal (or logical) basis for the NOPR's suggestion that wholesale customers with existing contracts containing valid notice of termination provisions can be forced to renegotiate such contracts to allow stranded cost recovery. Many of these commenters cite *Boston Edison Company* [279] and *Arizona Public Service Company* [280] for the proposition that notice provisions have been allowed and enforced. Many commenters contend that contract renegotiation is unfair because the policy would make the terms of existing contracts binding on only one party, while letting the other party unilaterally revise contract terms.

Some commenters, including the Electric Generation Association and the Iowa Utilities Board, generally oppose renegotiation, but would allow it in certain situations. They state that a utility's right to recover stranded costs should depend on the terms for which the parties have bargained. However, they recognize that there may be situations in which the parties' intent is not clearly defined. Accordingly, these commenters support renegotiation to supply missing terms to an ambiguous contract. Some commenters such as the Iowa Utilities Board maintain that companies should always be free to renegotiate contracts; however, they oppose allowing utilities to make unilateral filings to amend contracts that do not provide for unilateral amendment.

With regard to whether the renegotiation proposal should apply only to contracts between unaffiliated entities, some commenters (*e.g.*, Wisconsin Power, Sunflower) support the application of the renegotiation policy to both affiliated and non-affiliated entities alike. However, other commenters (*e.g.*, the Ohio Office of the Consumers' Counsel) recommend that the Commission not apply the proposed renegotiation rule to affiliated entities. They note that due to the mutual interest of affiliates, negotiations between them may not be arm's-length. These commenters urge the Commission to review all stranded investment agreements between affiliates to prevent cross-subsidization and to prevent interference with competition.

(ii) Three-Year Transition Period. With regard to the proposed transition period, although some commenters argue against permitting contract renegotiation, commenters generally raise no serious objections to three years as the period for contract negotiation. However, several commenters suggest that it is undesirable and unnecessary to delay the movement to competition for three years while contract renegotiations take place. For example, the Competitive Working Group argues that there is no assurance that stranded cost recovery will be resolved during the three-year period proposed in the initial notice. It suggests that the Commission could shorten the transition to competition while still providing for recovery of stranded costs by requiring that eligibility for recovery be conditioned on utilities agreeing to: (1) Grant wholesale customers the right to reduce or terminate purchase obligations under preexisting contracts and to convert to transmission-only service; (2) file comparable open-access transmission tariffs; and (3) mitigate the level of stranded assets by either divestiture or auction. The Competitive Working Group claims that these measures would ensure the move to competitive wholesale power markets.

DOE, Industrial Consumers, Enron and CLF also suggest linking the recovery of stranded costs to utility actions that will further wholesale competition. These commenters suggest linking the recovery of stranded costs to the filing of an open access transmission tariff or membership in an RTG. CLF notes that environmental as well as economic benefits may be achieved by linking the recovery of stranded costs to the retirement of environmentally unsuitable electric generating plants or initiatives that encourage the development and deployment of renewable and clean energy technologies.

Detroit Edison Company (Detroit Edison) suggests that the renegotiation period be the greater of (1) three years,

[278] Notable exceptions to this general observation include Southern California Edison Company, which opposes renegotiation of *Mobile-Sierra* contracts, and the Pennsylvania Public Utility Commission (Pennsylvania Commission) and the Vermont Department, which favor upholding the sanctity of contracts.

[279] 56 FPC 3414 (1976).

[280] 18 FERC ¶ 61,197 (1982).

(2) the term of any existing contract, or (3) the period of any moratorium on changes in rates established in existing settlement agreements. According to Detroit Edison, adoption of this provision would allow utilities that already have established long-term contracts or that have agreed to a moratorium on rate changes to honor previously negotiated agreements.

(b) Preliminary Findings. We reaffirm our proposal to permit the recovery of legitimate and verifiable stranded costs for a limited set of existing wholesale contracts, namely, contracts executed on or before July 11, 1994 that do not already contain exit fees or other explicit stranded cost provisions. We further reaffirm our desire that utilities and their customers attempt to renegotiate such contracts promptly to specify the rights and obligations of the parties. To that end, we encourage the parties to existing contracts that do not address stranded costs to reach a mutually agreeable resolution. If the parties negotiate such a provision and the seller is a public utility, the utility must file the provision with the Commission as an amendment to the existing requirements contract. Of course, in some cases, the parties may disagree in good faith about whether the utility's expectations that the customer would continue taking service were reasonable. If so, negotiations may prove unsuccessful.

In place of the three-year transition period proposed in the initial NOPR, we propose that, if an existing requirements contract does not contain an exit fee or other explicit stranded cost provision and is not mutually renegotiated to add such a provision: (1) A public utility or its customer may, at any time prior to the expiration of the contract, file a proposed stranded cost amendment to the contract under section 205 or 206; or (2) a public utility or transmitting utility may, at any time prior to the expiration of the contract, file a proposal to recover, through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier, stranded costs associated with any such existing contract. However, for a utility to be eligible for recovery of stranded costs, it must meet the evidentiary and procedural criteria discussed *infra.*

Consistent with the initial NOPR, if an existing contract includes an explicit provision for payment of stranded costs or an exit fee, we will assume that the parties intended the contract to cover the contingency of the buyer leaving the system. As proposed in the initial Stranded Cost NOPR and reaffirmed here, we will reject a stranded cost amendment to an existing contract that already contains an exit fee or stranded cost provision, unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to renegotiate the contract.

However, if a contract does not contain an exit fee or other explicit stranded cost provision, and the contract permits the seller and/or buyer to seek an amendment to the contract, the authorized party may seek an amendment to add a stranded cost provision. In addition, even if the contract contains an explicit *Mobile-Sierra* provision, the Commission reaffirms its preliminary determination that it is in the public interest to permit public utilities to seek unilateral amendments to add stranded cost provisions if the contracts do not already contain exit fees or other explicit stranded cost provisions. If a utility demonstrates that it has met the standards for recovery outlined in this Supplemental NOPR, we believe that its recovery of stranded costs will be in the public interest.

If neither of the parties to such a contract seeks and obtains acceptance or approval of an explicit stranded cost amendment, the Commission proposes to permit the public utility to seek recovery of stranded costs through its wholesale transmission rates. We also propose to establish procedures to provide an existing wholesale requirements customer who is contemplating switching suppliers, and using its existing supplier's transmission system in order to reach a new supplier, advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure. We believe that the following procedures would enable such a customer to make an informed decision whether or not to switch suppliers:

(1) A customer may, at any time prior to the termination date specified in its existing wholesale requirements contract, request the public utility to either: (i) Calculate the customer's maximum possible stranded cost exposure without mitigation, as of the date set forth in the customer's request; or (ii) provide the formula that the utility would use to calculate the customer's maximum possible stranded cost exposure without mitigation, to enable the customer to assess whether to contract for new generation service from another supplier. The customer should specify in its request, to the extent possible, pursuant to its rights under the power sales agreement with the seller, the date on which the customer would substitute alternative generation for the requirements purchase and the amount of the substitution. Any remaining requirements purchased from the existing supplier after this date should be clearly indicated. The customer may seek further information on how the stranded cost charge would vary as a result of choosing different dates or different amounts of substitute purchases. The customer also should indicate its preferred payment method(s) (*e.g.*, a monthly or annual adder to its transmission rate or an up-front lump-sum payment).

(2) The utility shall, within thirty days of receipt of the request, or other mutually agreed upon period, provide the customer: (i) The customer's maximum possible stranded cost exposure without mitigation; or (ii) the formula that the utility would use to calculate the customer's maximum possible stranded cost exposure without mitigation. The utility's response should indicate the period over which the utility proposes to charge the departing customer. There should be appropriate support for each element in the calculation or formula to enable the customer to understand the basis for the element. The utility should provide a detailed rationale for its proposal as to how long the utility reasonably expected to keep the customer. The utility also should address how it intends to mitigate stranded costs.

(3) If the customer believes that the utility has failed to establish that it had a reasonable expectation of continuing to serve the customer beyond the contract term or that the proposed maximum stranded cost charge without mitigation (or formula) is unreasonable, it will have thirty days in which to respond to the utility explaining why it disagrees with the charge. The parties should then attempt to reach a mutually-agreeable charge for stranded costs within a reasonable period.

(4) If the parties are unable to resolve the matter pursuant to the procedures specified in (1)–(3) above, the customer may either: (a) File a complaint with the Commission under section 206 of the FPA to seek a Commission determination whether the utility has met the reasonable expectation standard and, if so, whether the proposed maximum stranded cost charge (or formula) satisfies the other evidentiary standards set forth in this rule;[281] or (b) wait until the proposed stranded cost charge is filed under section 205 of the

[281] If a complaint is filed, neither the customer nor the utility could raise issues not identified in their earlier discussions. The burden of proof would be on the utility to satisfy the evidentiary standards related to stranded cost recovery.

FPA, and contest it at that time.[282] In either case, *i.e.*, a section 205 or 206 proceeding, the utility would only be able to seek stranded cost recovery according to the formula and other terms identified in its earlier discussions with the customer.

The above-described procedure would provide a customer an opportunity to know its maximum possible exposure as far in advance of its decision to change suppliers as the customer chooses (*i.e.*, the customer can file its request for a stranded cost computation at any time). If the customer decides to contest the proposed stranded cost charge, in either a section 206 or 205 proceeding, it will know its exact exposure once the Commission has completed its review of the proposed charge. This procedure attempts to address the *Cajun* court's concern that exposure to an unknown stranded cost fee will discourage customers from looking at other suppliers. At the same time, this procedure will permit recovery of legitimate stranded costs as set forth herein.

We strongly encourage utilities and their existing customers to attempt to resolve stranded cost issues through a mutually-agreeable exit fee or other stranded cost amendment to existing contracts that do not address stranded cost recovery.

We invite comments on our proposal to drop the three-year negotiation requirement originally proposed in the Stranded Cost NOPR, and instead to permit amendments to certain existing requirements contracts at any time prior to the expiration of the contracts, or to permit utilities to seek recovery through a departing customer's transmission rates at any time prior to the expiration of the power sales contracts. We also invite comments on our proposal to establish a procedure whereby a wholesale requirements customer with an existing contract that does not explicitly address stranded costs can obtain its maximum stranded cost exposure without mitigation from the utility and can seek Commission review of the utility's reasonable expectation claim and the utility's proposed stranded cost charge or formula.

(6) Filing Requirements for Wholesale Stranded Cost Recovery. The Commission proposes to amend Part 35, Chapter I, Title 18 of the Code of Federal Regulations to establish filing requirements for public utilities (as defined in FPA section 201(e)) and transmitting utilities (as defined in FPA section 3(23)) that seek stranded cost recovery. We reaffirm our view that the only circumstance in which transmitting utilities that are not also public utilities may seek stranded cost recovery from this Commission is through customer-specific surcharges to rates for transmission services under FPA sections 211 and 212, and that those surcharges may only apply to costs associated with existing contracts.

The proposed regulations define ''wholesale stranded cost'' as ''any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: (i) a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility, or (ii) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.''

We seek comment on whether the proposed definition of ''wholesale stranded cost'' should encompass the situation where a wholesale requirements customer ceases to purchase power from the utility that had been making wholesale requirements sales to such customer, and the customer does not thereafter become an unbundled transmission services customer of that utility. This situation might occur, for example, in a situation where the former requirements customer was in a non-contiguous service area and does not need unbundled transmission service from the former seller in order to purchase power from a replacement supplier.

Consistent with the initial Stranded Cost NOPR, the proposed regulations would permit a public utility or transmitting utility to seek recovery of wholesale stranded costs as follows. First, for stranded costs associated with new wholesale requirements contracts (*i.e.*, any wholesale requirements contract executed after July 11, 1994), the proposed regulations would allow recovery of stranded costs only if the contract explicitly provides for recovery of stranded costs.

Second, for existing wholesale requirements contracts (*i.e.*, any wholesale requirements contract executed on or before July 11, 1994), the proposed regulations would specify that a utility may not recover stranded costs associated with such contract if recovery is explicitly prohibited by the contract (including associated settlements) or by any power sales or transmission tariff on file with the Commission.

Third, for existing wholesale requirements contracts that do not address stranded costs through exit fee or other explicit stranded cost provisions, the proposed rule would allow a public utility to seek recovery of stranded costs only as follows: (1) if the parties to the existing contract renegotiate the contract in accordance with this rule and file a mutually agreeable amendment dealing with stranded costs, and the Commission accepts or approves the amendment; (2) if either or both parties seeks an amendment to the existing contract under sections 205 or 206 of the FPA, prior to the date the contract expires, and the Commission accepts or approves an amendment permitting stranded cost recovery; or (3) if the public utility files a request, prior to the date the contract expires, to recover stranded costs through an adder to a departing customer's transmission rates under FPA sections 205–206, or 211–212.

Fourth, if the selling utility under an existing wholesale requirements contract is a transmitting utility but not also a public utility, and the contract does not address stranded costs through an explicit exit fee or other stranded cost provision, the transmitting utility may seek to recover stranded costs through an adder to a departing customer's transmission rates under FPA sections 211–212. Such utility may not seek recovery of stranded costs through a section 211–212 transmission rate if the existing contract does contain an explicit exit fee or other stranded cost provision.

Fifth, for a retail-turned-wholesale customer, the proposed rule would allow a public utility or transmitting utility to file a request to recover stranded costs from the newly created wholesale customer through an adder to that customer's transmission rate.

Sixth, for customers who obtain retail wheeling, a public utility or transmitting utility may seek recovery through transmission rates only if the state regulatory authority has no authority under state law at the time retail wheeling is required to address stranded costs.

(7) Evidentiary Demonstration Necessary—Reasonable Expectation Standard.—In the Stranded Cost NOPR, we proposed, as part of the evidentiary demonstration that a public utility or transmitting utility must make to recover stranded costs in wholesale transmission rates, or through a unilateral amendment to the power sales contract, that the utility must show

[282] As discussed in section III.F.1.c(10) *infra*, retail customers contemplating becoming wholesale customers may use the same procedures.

that it incurred costs based on a reasonable expectation when the costs were incurred that the applicable contract would be extended.[283] We indicated that, in these situations, the question of whether a utility had a reasonable expectation of continuing to serve a customer is a factual matter that will depend on the evidence produced in each case. We further proposed that a notice provision in a contract would create a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the period provided for in the notice provision. We invited comments with regard to these proposals and also asked whether we should adopt a minimum notice period that would create a presumption that the utility had no reasonable expectation of continuing to provide service beyond such period (e.g., a five-year notice period).[284]

(a) Comments. Commenters express a variety of views on the reasonable expectation standard for extra-contractual cost recovery. Some commenters (*e.g.*, the Transmission Access Policy Study Group) do not believe there is a legal basis to permit the claimed expectation of indefinite renewal of a contract to override a customer's express contractual termination rights. These commenters argue that there has never been any assurance that utilities will be allowed to recover all of their costs, no matter how incurred. These commenters assert that utilities have been on notice for years that customers may try to exercise their contractual right to terminate service when their contracts end, and that utilities would not be entitled to any contract extensions or other relief. These commenters state that the reasonable expectation test is an inadequate basis for denying customers their contractual termination rights.

Other commenters (*e.g.*, Environmental Action) state that if reasonable expectations (as opposed to contract language) are relevant, one must determine both the utility's and the customer's reasonable expectations. These commenters support the concept of contract symmetry; if there is no obligation to serve beyond the contract term, imposing an obligation to pay beyond the contract term is asymmetrical.

With regard to the Commission's proposal that a notice provision in an existing contract creates a rebuttable presumption that there is no reasonable expectation that the contract will be renewed, many investor-owned utility commenters, as well as the Florida Commission and the Texas Commission, question whether a notice provision constitutes sufficient grounds for such an assumption. Because of the obligation to serve and the long lead time needed to construct new base-load generating units, they argue that a utility could have been found to be imprudent if it did not plan for and build sufficient generating capacity to meet its service obligations. These commenters maintain that it would have been unreasonable for a utility to assume that a customer that is served under a contract with a notice provision that has been repeatedly renewed would not again renew the contract. These commenters maintain that a notice provision is not sufficient to demonstrate a ''meeting of the minds'' on this issue.

TVA states that the notice provisions in its contracts in no way lessen its intention to serve its customers. TVA states that its legislative provisions, planning process, and history all support the assumption that it will continue serving its wholesale customers indefinitely.

Certain customer groups, such as the TDU Customers and the Wisconsin Wholesale Customers (Wisconsin Customers), believe that the Commission should make the rebuttable presumption stronger, *i.e.*, that contracts with notice provisions should absolutely preclude stranded cost recovery. Wisconsin Customers state that there should be no opportunity for renegotiation to include stranded cost provisions in contracts with reasonable notice provisions.

(b) Preliminary Findings. We believe we should retain a reasonable expectation standard as part of the evidentiary demonstration that a public utility or transmitting utility must make. Whether a utility had a reasonable expectation of continuing to serve a customer, and for how long, will be determined on a case-by-case basis. Depending on all of the facts and circumstances, a reasonable expectation that a contract would be extended could be established, for example, by: (1) Whether the customer had access to alternative suppliers; (2) a showing that the parties' actual conduct or course of dealing has been to renew the contract upon its scheduled expiration; (3) evidence that a utility has recovered construction-work-in-progress (for projects that would enter service after the scheduled contract expiration) from a particular customer without the customer's objection; or (4) communications between supplier and customer concerning system planning, such as an indication by a buyer that the seller should continue to include the buyer's load in the seller's resource planning beyond the contract term.[285]

In addition, as proposed in the initial NOPR, we believe that the existence of a notice provision in a contract should create a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the period provided for in the notice provision. Of course, evidence that a contract with a notice provision has been repeatedly renewed (the scenario described by commenters opposing the creation of a rebuttable presumption) may, depending on the particular case, be sufficient to rebut the presumption that the utility had no reasonable expectation of contract renewal.

Further, we will not adopt a minimum notice period for purposes of applying the reasonable expectation rebuttable presumption. We believe that whether a utility had a reasonable expectation of continuing to serve a customer, and for how long, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provision in the contract, will depend on the facts of each case. In these circumstances, we do not believe that a generic minimum notice period would be appropriate.

In addition, a contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a new contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.

We seek further comment on the following specific aspect of the reasonable expectation standard: Should the reasonable expectation standard apply in a case where a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and where, in order to make such a sale possible, transmission service has been rendered by an intervening utility or utilities? Should the Commission take this as conclusive evidence that the customer had a choice of wholesale suppliers and, therefore, that the seller had no reasonable expectation that the contract would be extended? In the alternative, should the Commission choose to provide the seller with an opportunity to prove that it had a reasonable expectation, what weight should be given to the fact that transmission service was rendered by the intervening utility or utilities? Finally, in the event that the seller establishes that it had a reasonable expectation, and the former wholesale customer does not take unbundled

[283] Stranded Cost NOPR at 32,873–74.

[284] *Id.* at 32,874.

[285] See *id.* at 32,874.

transmission service from the former seller, what means ought to be available for the collection of stranded costs?

(8) Identification of Recoverable Wholesale Stranded Costs. The Stranded Cost NOPR proposed, as part of the evidentiary demonstration necessary for wholesale stranded cost recovery, that a utility show that the stranded costs it incurred are not more than the customer would have contributed to the utility had the customer remained a wholesale requirements customer of the utility. We invited comments in the initial NOPR on what would constitute reasonable compensation for stranded costs and on how to determine the amount of stranded costs that the departing customer may be liable to pay. For example, we asked whether it would be reasonable to limit the annual amount of stranded costs to what the departing customer would have contributed to the utility's capital (customer revenues minus variable costs), or whether an alternative concept would be appropriate. We also requested comments as to what would constitute a ''reasonable compensation period'' over which to determine a customer's liability for stranded costs (*e.g.*, five years, ten years, or some other period). We indicated that the present value of the customer's liability could be the discounted value of an annual amount for such reasonable compensation period and that this total amount could be paid in a lump sum or over any mutually agreeable period.[286]

We also assumed in the NOPR that stranded costs will be dominated by generating capacity, but stated that it is appropriate to consider stranded costs more broadly, including the possibility that fuel supply costs, purchased power costs (including QF costs), nuclear decommissioning costs, regulatory assets, and possibly other utility obligations may be stranded. Accordingly, we invited public comment on what categories of costs, in addition to investment costs, should be eligible for stranded cost recovery.[287]

(a) Comments. (i) Acceptable Calculation Methods. Most commenters were not very specific regarding how to calculate the level of recoverable wholesale stranded costs. However, commenters that address this issue generally fall into three groups.

The first group reflects the position of EEI and most investor-owned utility commenters. This group proposes an asset-by-asset review of stranded investments (including contractual liabilities, regulatory assets, and certain social program costs) to develop a total company estimate of stranded costs that need to be recovered. These costs could then be allocated among customers to determine a hypothetical cost-of-service measure of stranded cost liability. From this amount, the utility would subtract wheeling service revenues and any revenues from mitigation measures taken. As explained in more detail below in the discussion of allowable cost categories, investor-owned utility commenters argue for inclusion of a broad number of investments, expenses and future costs in the revenue requirement calculation of recoverable stranded costs. Commenters that support this approach also suggest that costs are properly included in the calculation (*i.e.*, are recoverable wholesale stranded costs) to the extent that such costs have been ruled to be prudently incurred in a state determination.

Some commenters, however, oppose a hypothetical cost-of-service calculation approach to determining recoverable stranded costs arguing that it will engender litigation. These commenters note that generating units are not built, and specific costs are not generally incurred, on behalf of individual customers. According to these commenters, attempting to define specific components of stranded costs associated with a specific departing customer is inconsistent with utility investment planning and historical cost incurrence.

A second approach for determining recoverable wholesale stranded costs is based on ''revenues lost'' as a result of a customer switching suppliers. Most non-investor-owned utility commenters (*e.g.*, state commissions and customers) and some investor-owned utilities (*e.g.*, Commonwealth Edison Company (Commonwealth Edison), Utility Working Group (UWG)[288]) support this method of calculation. Commenters that support this approach argue that the calculation is less complex than a hypothetical cost-of-service approach and avoids an asset-by-asset review with its attendant accounting and tracking complexities.

Many commenters note that the revenues lost approach recognizes that utilities that made multiple investment decisions under the prior regulatory scheme compact expected a revenue stream from their customers to cover the costs of those investments. Under this approach, the measure of recoverable stranded costs is the difference between revenues expected from a customer under traditional regulation and the expected revenues in a competitive market. Some commenters suggest further limitations on the revenue stream calculation, *i.e.*, calculating revenues on a present value basis, or using current revenues as the ceiling for utility expected revenues under the prior regulatory regime. According to commenters, these limitations serve at least two purposes: (1) Simplifying the calculation; and (2) creating incentives for utilities to mitigate stranded costs, which will shorten the transition period to a competitive market.

Some commenters, including Public Service Electric and Gas Company (Public Service Electric), also point out that this approach is consistent with resource acquisition. These commenters note that specific investment decisions are not made on a retail/wholesale or customer-by-customer basis, but rather on the basis of resources needed to meet load, *i.e.*, generation plant additions are made based on an analysis of total system needs. Commenters also note that under a revenues lost approach, specific investments/assets do not need to be assigned (or tracked) to a particular event causing stranded costs.

A few commenters (*e.g.*, APPA, Electric Generation Association, Illinois Commission) advocate a third method of calculating the level of recoverable wholesale stranded costs. Under this method, which is a ''netting'' or ''market analysis'' approach, recoverable stranded costs would be determined based on the difference between embedded capital costs and the market value of stranded assets. While this approach is not dissimilar to a ''revenues lost'' approach, the level of stranded costs is generally determined only after a future action with respect to the stranded costs, *i.e.*, auction, divestiture or other future disposition of assets. Other commenters (*e.g.*, Central Vermont Public Service Corporation, Long Island Lighting Company (Long Island Lighting)) suggest variations of this ''netting'' approach, such as comparing the utility's revenues with some measure of the utility's marginal cost of requirements service. Commenters claim that, in a competitive market, the marginal cost would equal the market price. Thus, under this

[286] *Id.* at 32,874–75.

[287] *Id.* at 32,867.

[288] The Utility Working Group members participating in UWG's comments in this proceeding are Dominion Resources, Inc., Duke Power Company, Duquesne Light Company, Entergy Corporation, General Public Utilities Corporation, Niagara Mohawk Power Corporation, Northern States Power Company, Pacific Gas and Electric Company, Portland General Electric Company, Public Service Electric and Gas Company, San Diego Gas & Electric Company, Southern California Edison Company, and Wisconsin Electric Power Company.

approach, recoverable stranded costs are the excess above market value of the stranded assets. Duke Power Company notes that mitigation measures would be unnecessary if this method were used to calculate recoverable stranded costs because the utility's marginal cost (not just its variable expenses), *i.e.*, the market price of the stranded assets, is used as the ''offsetting'' value in the calculation.

(ii) Reasonable Compensation Period (how long utility could reasonably expect to keep customer). Commenters support a wide range of time periods as appropriate for determining a customer's stranded cost liability. Almost all of the commenters, however, request that the Commission provide flexibility in this regard and not establish a generic recovery period so that a variety of recovery mechanisms can be accommodated.

Some state commission commenters (*e.g.*, Illinois Commission) support a limited time period for determining a customer's stranded cost liability as an incentive for utilities to mitigate stranded costs. According to the Illinois Commission, limiting the time period over which a customer's stranded cost liability is to be determined should encourage utilities to ''fervently re-market the services produced by the potentially stranded resources.'' [289] Utility customer commenters (*e.g.*, city of Las Cruces, TDU Customers) also support a limitation on the period over which stranded costs would be determined. These commenters propose limiting the reasonable compensation period to the lesser of the contractual notice period; the remaining portion of the stated term of a contract; a five-year period (as a maximum reasonable time to plan for mitigation measures); or the utility's planning horizon.

Some investor-owned utility commenters (*e.g.*, EEI, Centerior Energy Corporation), on the other hand, oppose limiting the period over which a customer's stranded cost liability would be determined. EEI, for example, states that as a general rule, the departing customer should be responsible for its regulated rate less the utility's marginal cost and mitigating revenue. It contends that the period of such responsibility should continue until the utility needs the capacity freed up by the departing customer to meet retail load growth or firm wholesale obligations. In effect, these commenters support an open-ended opportunity to recoup wholesale stranded costs. They argue that the recovery period should continue as long as possible to ensure that native load customers are held harmless.

(iii) Allowable Cost Categories. Almost all commenters agree that stranded costs should not include variable expenses. The majority of customer commenters either: (1) Support the Commission's proposed categories; or (2) do not express an opinion regarding cost categories that are appropriate for recovery because they support the use of some type of ''revenues lost'' approach for determining recoverable costs, which does not require the identification of specific utility investments or expenses.

Many investor-owned utility commenters, however, contend that, in addition to the items identified in the NOPR, recoverable stranded costs should include a broad number of other investments, expenses and future costs. These commenters propose that the additional items that are eligible for recovery should include, but not be limited to:

- Construction work in progress;
- Regulatory assets, such as phase-in plans for new generation plant, and accrual accounting requirements (*e.g.*, income tax normalization, accounting for pension and PBOP costs);
- Actual nuclear decommissioning costs as well as a utility's pro rata obligation to dismantle and decontaminate DOE's uranium enrichment facilities;
- All fuel costs pending recovery via fuel adjustment mechanisms;
- Mandatory social program costs including DSM, low-income assistance, environmental clean-up and various R&D projects;
- Clean Air Act compliance costs;
- Storm damage expenses; and
- Other unknown future liabilities.

In addition, EEI states that before 1992, *i.e.*, pre-EPAct, no regulatory commission explicitly authorized a rate of return that compensated a utility for the risk of future retail competition. EEI notes that after EPAct only four regulatory commission decisions have addressed this issue. Because the risks of the new competitive market were neither contemplated by investors nor compensated by regulators under existing ratemaking, EEI argues that the cost of such risk must also be included as a category of costs eligible for stranded cost recovery.

Public Power Council suggests that there are two dangers in creating lists of eligible and ineligible costs: (1) Wasteful regulatory battles are likely; and (2) utility managers will have the incentive to reduce ineligible costs, while ignoring opportunities to reduce eligible costs.

(b) Preliminary Findings. The Commission preliminarily concludes that the determination of recoverable stranded costs should be based on a ''revenues lost'' approach rather than a hypothetical cost-of-service approach. The Commission believes that this approach has greater benefits than a hypothetical cost-of-service approach. A ''revenues lost'' approach avoids the asset-by-asset review that is required by alternative cost-of-service approaches in order to calculate recoverable stranded costs. Cost allocation procedures are also minimized. Moreover, the Commission believes that this approach will be easier to apply, thereby minimizing the cost of administering stranded cost recovery.

The Commission's experience in the natural gas industry is relevant here. Certain pipelines faced with take-or-pay obligations under uneconomic natural gas supply contracts have developed a ''pricing differential'' mechanism that has enabled them to honor existing take-or-pay obligations, while attempting to renegotiate the contracts.[290] Under this mechanism, the pipeline continues to meet its contractual purchase obligation and continues to market the gas purchased through its separate marketing operation. The ''differential'' or ''revenues lost'' between the purchase price and the sales price is passed through as a transition cost.[291]

Under the revenues lost method that we propose here, the utility would calculate a customer's stranded cost liability by subtracting the competitive market value of the power the customer would have purchased from the utility (and the basic revenues from the transmission service) had the customer continued to take service under its contract from the revenues that the customer would have paid the utility. As discussed in section III.F.1.c(9) *infra*, the utility must attempt to mitigate stranded costs by marketing stranded power supplies.

The Commission seeks further comments on the revenues lost approach. In particular, what would be the appropriate method to calculate what the utility's revenue stream would have been had the customer continued service (*e.g.*, current revenues based on current service levels, or should projection and adjustments reflecting changes in the revenue stream be permitted)? The Commission also seeks comments on the appropriate method to

[289] Illinois Commission comments at 61–62.

[290] Texas Eastern Transmission Corporation, 63 FERC ¶ 61,100 at 61,507 (1993).

[291] For details on the mechanics of this program, see Texas Eastern Transmission Corporation, 63 FERC at 61,507–08; Texas Eastern Transmission Corporation, 64 FERC ¶ 61,378 (1994).

calculate the revenues that the utility would receive in a competitive market for the stranded assets. Should the Commission require the utility to track the actual selling price of the power over time, or should it require the utility to use an up-front approach, such as an estimate of the forecasted market value of the power for the period during which the customer would have taken service? Should the Commission allow prices in futures markets or forward markets to be used in an up-front approach, assuming such financial instruments become available? In addition, how should revenues received as a result of mitigation measures be reflected in the determination of the amount of recoverable stranded costs? What special accounts, if any, should be created to track revenue liability for specific customers, revenues from mitigation measures, and other revenues received by the utility that offset the stranded cost liability? Once determined, should any adjustment be permitted to the revenues that the utility claims will be realized in a competitive market for its stranded assets, and if so, how often and under what circumstances?

With regard to establishing a reasonable compensation period (*i.e.*, setting a limit on how long the utility could have reasonably expected to keep the customers), we do not believe that a one-size-fits-all approach is appropriate. A particular customer's stranded cost liability will depend, in each instance, on such case-specific factors as whether the utility can demonstrate that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and, if so, for how long. Therefore, we believe it appropriate to permit utilities and their customers some flexibility with regard to the period over which a customer's stranded cost liability would be determined. However, we will not allow an open-ended opportunity to recoup wholesale stranded costs. Although our preliminary finding is that a one-size-fits-all approach is not appropriate, we seek further comment with respect to whether the Commission ought to establish presumptions or, in the alternative, absolute limits on a customer's maximum liability in those situations where a utility establishes that it had a reasonable expectation that the contract would be extended. For instance, would it be appropriate to pick an outer limit equal to the revenues that the utility would lose during the length of one additional contract extension period, or during the length of the utility's planning horizon? What other events or criteria might the Commission use to establish either presumptions or absolute limits on the time period over which the customer's liability for stranded costs would be determined?

Our decision to adopt a revenues lost approach for determining recoverable stranded costs, which avoids an asset-by-asset review, in effect eliminates the need to enumerate specific categories of costs that may be recovered. However, there may be special categories of costs that are properly allocated to departing customers and that are not captured in the revenues lost approach. For example, nuclear decommissioning costs may not be reflected, or may not be fully reflected, in current requirements rates. To the extent this is true, a departing customer may be ''escaping'' from costs that it caused as a result of taking power service from its supplier during the time that the nuclear plant was operating. We seek comments on whether there are special costs that warrant some special consideration in the determination of stranded cost liability under a revenues lost approach, and if so, how they should be treated. We also solicit comments as to whether the Open Access NOPR raises any additional implementation or other issues affecting stranded cost recovery as proposed here.

(9) Mitigation Measures. As part of the evidentiary demonstration that a utility must make in order to recover stranded costs, the Stranded Cost NOPR would require the utility to show that it has taken and will take reasonable and prudent measures to mitigate stranded costs. The Commission proposed in the initial NOPR that adequate mitigation measures might include: (1) Evidence that the utility has tried to market the asset or assets, market the generating capacity, reconfigure or delay investment in or purchase of new generating capacity, or reform fuel supply contracts that form the basis for the stranded costs charge, and that such measures to mitigate stranded costs will continue for the entire period for which the stranded costs charge will be paid; or (2) the utility has given the customer the option to market the generating capacity or supply of fuel or purchased power that forms the basis for the stranded cost charge in order to afford the customer an opportunity to lower its stranded costs charge. We invited comment on the mitigation requirement and what reasonable measures to mitigate may include.

(a) Comments. Although there is nearly unanimous support for requiring that mitigation measures be taken, commenters raise several issues regarding how mitigation should be implemented and the effectiveness of such a requirement.

As noted above, many investor-owned utility commenters argue that stranded costs should be defined to include costs other than capital investment in utility property. According to these commenters, stranded costs also may include environmental clean-up costs, decommissioning costs, and regulatory assets resulting from cost recovery deferrals. Unlike capacity, these costs cannot be ''marketed.'' Therefore, mitigation measures cannot be taken with respect to these costs. Thus, according to some commenters, there is a category of ''unmarketable'' stranded costs for which mitigation efforts to reduce the level of the costs are not possible.

Many commenters (*e.g.*, Texas Commission, TDU Customers) contend that a mitigation requirement will be more effective if incentives to mitigate are created. These commenters suggest several options, including:

• Limiting recovery of stranded costs to current rate levels (no projections of increases in stranded costs for future periods);

• Requiring shareholders to shoulder some cost responsibility (to ensure that mitigation measures will be aggressively pursued); and

• Requiring any stranded investment to be offered for sale, either with the departing customer permitted to ''sell'' the stranded investment, or through some form of auction.

Other commenters suggested that effective mitigation would require auctioning off stranded assets or some type of general divestiture of assets by the utility that is allowed to recover stranded costs.

Many commenters acknowledge that revenues from mitigation measures should reduce the amount of wholesale stranded costs. An issue is raised, however, regarding how revenues associated with mitigation measures should be credited. Given the overall preference by commenters supporting stranded cost recovery for direct assignment of stranded costs to a departing customer, explicit crediting mechanisms and accounting requirements—and perhaps new accounts or subaccounts—would be needed to keep track of amounts owed by those assessed wholesale stranded costs. Consequently, these commenters contend that decisions regarding who should pay (and how) for wholesale stranded costs must be coordinated with decisions regarding the implementation of required mitigation measures so that parties receive appropriate credits.

(b) Preliminary Findings. We note that the revenues lost approach for determining recoverable stranded costs encompasses mitigation measures because it reduces the amount of stranded costs recoverable by a utility by the market price of the power that the customer no longer takes under its contract. Thus, our suggestion in the initial NOPR that revenues associated with mitigation measures be credited to the departing customer through reductions to that customer's surcharge is in effect accomplished by adoption of the revenues lost approach. This is particularly so if mitigation is reflected through a one-time, up-front estimate of the future market value of the power, and is not trued-up over time. Nonetheless, we emphasize that mitigation as a general matter remains important, and seek comment regarding implementation of a mitigation requirement. For example, if mitigation is trued-up over time, how should the Commission ensure that the utility takes all reasonable steps to mitigate its own costs so as to minimize what the customer would have paid? How should the Commission ensure that the utility does its best to sell the power at its highest possible value so as to mitigate the customer's stranded cost liability? Are there other mitigation measures that should be taken into account (*e.g.*, efficiency improvements that a utility would have undertaken regardless of whether the particular customer continued to take power under its contract, or cost savings resulting from the buy-out of a fuel contract made possible by the customer's departure)?

(10) Federal Forum for ''Retail'' Stranded Cost Recovery and Proposed New Definition of ''Wholesale'' Stranded Costs. In the initial NOPR, the Commission described two general ways in which retail stranded costs are likely to occur: (1) A retail franchise customer or group of such customers may, through state or local government action, become a wholesale customer that can then obtain unbundled transmission services in order to reach a new power supplier; and (2) a retail franchise customer may obtain voluntary unbundled retail transmission services from its existing power supplier in order to reach a new power supplier, or there may be a State or local government action that results in the existing supplier providing such retail transmission services. The Commission requested comments concerning the extent to which the Commission should provide a forum for resolving retail stranded cost issues. The Commission proposed two alternatives for addressing this issue. Under the first alternative, the Commission proposed that it would not entertain a request for retail stranded cost recovery if, in a specific circumstance, an appropriate state authority explicitly considers and deals with retail stranded costs and there is no conflict within or among state regulatory bodies regarding a state's disposition of the issue. However, in the absence of a clear expression by an appropriate state authority that it has dealt with the issue, or in the event of a conflict between states or among state officials within a single state, the Commission proposed to entertain requests to recover retail stranded costs. Under the second alternative, the Commission proposed not to entertain any request for recovery of retail stranded costs. Under this alternative, we proposed that state or local authorities would be the only forum for addressing the issue.[292]

(a) Comments. Most of the state commissions comment that the Commission should not provide a forum for addressing retail stranded cost issues. The Massachusetts Department of Public Utilities suggests Commission involvement only if a conflict arises through disparate stranded cost treatment by different states that the states are unable or unwilling to resolve. The Pennsylvania Commission suggests Commission involvement in retail stranded cost issues only if states have lost jurisdiction (for instance, due to municipalization). Most of the state commissions argue that retail costs are subject to exclusive state jurisdiction and that action or inaction by a state or any differences between state actions are matters to be resolved by the courts, not the Commission. Many of these commenters (*e.g.*, NARUC) note that numerous differences in ratemaking currently exist among states and that the Commission has not attempted to resolve those differences; they see no distinction with regard to retail stranded cost recovery. Some state commissions also argue that the possibility of Commission involvement in retail stranded cost recovery could introduce ''forum shopping.''

The New York State Public Service Commission (New York Commission) suggests that the Commission provide a backstop to the states only if a state has taken no action regarding retail stranded costs. The Ohio Public Utilities Commission (Ohio Commission) and the Wyoming Public Service Commission suggest that the Commission become involved in retail stranded costs only at the request or petition of a state.

[292] Stranded Cost NOPR at 32,878–79.

Commenters representing investor-owned utilities, on the other hand, overwhelmingly agree that the Commission should provide a forum for resolving retail stranded cost issues. They propose a broad range of scenarios in which Commission involvement in retail stranded cost recovery is appropriate.

EEI, Commonwealth Edison, Florida Power and Northern States Power Company argue that the Commission should act as a backstop to state commissions with authority to address retail stranded cost issues: (1) To address yet undefined questions; (2) when no state commission action is taken; or (3) when state commission action is not taken in a fair and timely manner or results in the confiscation of utility property.

Allegheny Power, Arizona Public Service Company and Virginia Electric and Power Company argue that the Commission should provide a forum to address situations in which states allegedly have no authority to address retail stranded cost issues (primarily municipalization).

The Coalition for Economic Competition, Entergy, Utility Working Group, and the Nuclear Energy Institute urge the Commission to address situations in which state policy is inconsistent with Commission policy. In fact, many investor-owned utilities advocate the establishment of uniform national guidelines for stranded cost recovery that will be applicable to both wholesale and retail stranded costs. These commenters contend that the Commission is the only body capable of fulfilling this role.

Houston Lighting & Power Company urges the Commission to address retail stranded costs whenever retail stranded costs have a substantial adverse impact on interstate transmission.

Two investor-owned utilities support Commission involvement in retail stranded cost issues only in limited circumstances. Entergy contends that Commission involvement is necessary only if state jurisdiction is evaded (*i.e.*, certain cases of municipalization). Public Service Electric states that Commission oversight is needed to ensure that final results are consistent with Commission guidelines and are pro-competitive.

Commenters representing small customer interests, such as Electric Consumers' Alliance and the National Black Caucus of State Legislators, support Commission involvement in retail stranded cost issues in order to ensure that large customers that leave the system do not evade their fair share of stranded costs to the detriment of residential and other small customers.

Commenters representing municipal and electric cooperatives (such as APPA, TAPS and SCOOP), commenters representing independent power producers (such as the National Independent Energy Producers), commenters representing industrial customers, some customer advocacy group commenters (such as Industrial Consumers, American Forest, and the National Association of State Utility Consumer Advocates (NASUCA)), and commenters representing environmental groups (such as CLF) generally oppose Commission involvement in retail stranded cost issues.

DOE agrees with the Commission that retail stranded cost recovery is primarily a state issue. However, DOE states that the Commission has correctly determined that it has authority to regulate the rates, terms and conditions of retail transmission service. Accordingly, DOE supports Commission involvement in retail stranded cost issues.

DOE notes that states may decide to make retail competition contingent upon the recovery of stranded costs by their jurisdictional utilities. DOE states that the Commission does not appear to have considered the possibility that a utility may seek recovery of retail-related stranded costs through a retail transmission tariff filed with this Commission that has the support of the state commission. DOE submits that the Commission, as a matter of policy, should allow utilities to file tariffs for retail transmission service that recover stranded retail costs when such filings have the support of the affected state commissions. However, DOE states that the Commission should not give deference to tariffs for retail transmission service that contain a provision for stranded cost recovery if the tariff is opposed by any state commission that has a material interest in the filing.

Public Service Electric states that due to the vertical integration of electric utilities, the distinction between wholesale and retail stranded costs is merely a matter of cost allocation. It contends that utilities generally do not have specific generating facilities in place to serve strictly wholesale customers, but rather include wholesale customer loads into their planning models as if they were retail customers. Public Service Electric thus concludes that no distinction between wholesale and retail stranded costs is necessary for purposes of evaluating stranded cost recovery.

In contrast, other commenters contend that there are inherent differences between retail and wholesale stranded costs, resulting primarily from the different regulatory regimes in place. These commenters state that, at the state level, a utility provides retail service pursuant to a ''regulatory compact'' under which the utility undertakes an obligation to serve retail customers in exchange for an exclusive service franchise. In contrast, they submit that the utility's obligation to serve a customer at the wholesale level is established through contract. Some commenters conclude that these differences necessitate different approaches for recovery of wholesale and retail stranded costs.

Several commenters (*e.g.*, Duke, Entergy, Long Island Lighting, Nuclear Energy Institute,[293] Public Service Electric, Coalition for Economic Competition, Utility Working Group) request that the Commission issue a uniform national set of standards to govern the treatment of all stranded investment (both retail and wholesale), irrespective of jurisdiction with respect to retail stranded costs.

In contrast, several of the state commission commenters emphasize a need for flexibility in dealing with retail stranded costs in lieu of a one-size-fits-all solution, which they argue may fail to address important differences between states. Accordingly, several of the state commission commenters, including the Alabama, California, Indiana, Michigan, and New York Commissions, urge that the Commission develop in cooperation with the state commissions a flexible approach to retail stranded cost recovery through various means such as joint boards or through more informal conferences or other joint forums.

With respect to the issue of stranded costs caused by retail-turned-wholesale customers, EEI and several investor-owned utilities (particularly those in Michigan, New York and California) maintain that the most important stranded cost issue before the Commission at this time is the formation of new municipal utilities. These commenters urge Commission involvement in the recovery of stranded costs resulting from this action. EEI notes that most states have constitutions or laws that permit municipalization, through which groups of retail customers may, in effect, become wholesale customers and thereby transfer primary regulatory responsibility for regulating sales to such entities from a state commission to the Commission.

EEI argues that in most instances the Commission will be the regulatory body that will have to consider stranded cost recovery issues resulting from municipalization. EEI states that in approximately 28 states, there is virtually no limitation on the ability of municipalities to form utilities or to oust current suppliers;[294] these states will be unable to protect their utilities from stranded costs. According to EEI, only 14 state commissions have some jurisdiction over the creation or expansion of municipal utilities,[295] and only a few states require reimbursement for stranded generation or for lost earnings. Moreover, EEI notes that condemnation proceedings based on eminent domain principles often do not consider regulatory policies regarding stranded cost assignment and recovery.

NARUC, on the other hand, argues that states and/or state commissions have the ability to address all retail stranded cost issues. From NARUC's perspective, the recovery of stranded costs due to municipalization is a matter to be addressed by state authorities. Appendix D to NARUC's comments contains information regarding state practices and policies in the areas of municipalization and newly-municipalized service territory (*i.e.*, annexation). While policies do vary among the states, NARUC as well as most state commission commenters (*e.g.*, Iowa Commission) maintain that state authorities (commissions, courts and legislative bodies) clearly have the ability to impose stranded asset payments on new municipal utilities. NARUC contends that resolution by state authorities is mandated by the legal authority of the states to act, and does not depend upon Commission deference to the states. NARUC also cautions the Commission against becoming an appellate body for reviewing state determinations that allegedly overrecover or underrecover stranded costs.

However, NARUC suggests two situations where Commission involvement with stranded cost recovery in a municipalization scenario

[293] Nuclear Energy Institute's utility members operate all (109) of the nuclear power plants in the United States.

[294] EEI states that these states are Arizona, Connecticut, Delaware, Florida, Georgia, Idaho, Illinois, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Montana, Nevada, New Jersey, New Mexico, New York, North Dakota, Ohio, Oklahoma, Oregon, Rhode Island, South Dakota, Tennessee, Utah, Virginia, Washington and Wyoming.

[295] EEI states that these states are Alaska, Arkansas, Iowa, Indiana, Maryland, Massachusetts, North Carolina, New Hampshire, South Carolina, South Dakota, Texas, Vermont, West Virginia and Wisconsin.

is reasonable. The first case is when a state determines that the appropriate cost recovery mechanism would involve a wholesale transmission rate beyond the state's jurisdiction. The second case is when the sequence of events or the timing of the transaction creates some ambiguity regarding the retail or wholesale character of the costs (*e.g.*, the Massachusetts Bay Transit Authority case cited in the NOPR).

Some commenters (*e.g.*, Florida Commission) request joint federal/state consultation on the issue of municipalization. The Florida Commission also requests that the Commission delay the effectiveness of wholesale contracts resulting from municipalization until retail stranded cost issues are resolved.

(b) Preliminary Findings. As discussed in the initial NOPR, as a general matter we believe that both this Commission and state commissions have the legal authority to address stranded costs that result from retail customers becoming wholesale customers who then obtain wholesale wheeling, or from retail customers who obtain retail wheeling, in order to reach a different generation supplier. Based on an analysis of all the comments received, we propose to exercise our authority to address stranded costs as follows.

Because the vast majority of commenters have urged the Commission not to assume responsibility for retail stranded costs, except in certain circumstances, we have concluded that it is appropriate to leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. The circumstances under which we will entertain requests to recover stranded costs caused by retail wheeling are when the state regulatory authority does not have authority under state law to address stranded costs at the time the retail wheeling is required. We continue to believe that utilities are entitled, from both a legal and policy perspective, to an opportunity to recover all of their prudently incurred costs. In addition, as discussed further below, we believe the Commission should be the primary forum for addressing recovery of stranded costs caused by retail-turned-wholesale customers.

With regard to stranded costs caused by retail wheeling, we emphasize that we will not allow states to use the interstate transmission grid as a vehicle for passing through any retail stranded costs, with the limited exception discussed above. Only if the state regulatory authority does not have authority under state law at the time the retail wheeling is required to resolve the retail stranded cost issue will we permit a utility to seek a customer-specific surcharge to be added to an unbundled transmission rate. We have accepted the view that stranded costs caused by retail wheeling are primarily a matter of local or state concern. Thus, these costs generally must be passed through in a manner that does not involve ''transmission of electric energy in interstate commerce'' as that phrase is used in the FPA. We are proposing to prohibit the pass-through of these costs on interstate transmission facilities except in the limited circumstance described. As discussed in section III.F.1.c(11), we believe that most states have a number of mechanisms for addressing stranded costs caused by retail wheeling, as well as retail-turned-wholesale customers. In addition, as further discussed in section III.F.1.c(12), we are proposing to define ''facilities used in local distribution'' under section 201(b)(1) of the FPA. Rates for services using such facilities to make a retail sale are state-jurisdictional. States therefore will be free to impose stranded costs caused by retail wheeling on facilities or services used in local distribution.

At this juncture, the Commission is comfortable with this approach and our hope is that a federal forum for recovery of retail stranded costs ultimately will not be necessary. When states address retail stranded costs caused by retail wheeling, the Commission holds the strong expectation that states will provide procedures for, and the full recovery of, legitimate and verifiable stranded costs. This is the same standard we set out for wholesale stranded costs. We do so as part of our goal to assure a smooth and orderly industry transition to competition that is fair to all affected parties. In this proposal we also set out procedures that all parties can use to seek equitable treatment of stranded cost recovery. Again, we expect a state providing for direct access to provide similar procedures. We know that states are aware and concerned about the impacts of providing direct access as shown by many state comments. Based on this awareness and concern, we anticipate state approaches to retail stranded costs not unlike our approach to wholesale stranded costs. Although our hope is that a federal forum will not be necessary, we will watch with interest the states' efforts to address the retail stranded cost problem.

We believe this approach represents an appropriate balance between federal and state interests. It ensures that the wholesale market, except in a narrow circumstance, will not be burdened by retail costs. It also helps to ensure that one state will not be able to burden customers in another state with stranded costs due to retail wheeling.

We have a different view with regard to stranded costs caused by retail-turned-wholesale customers. If a retail customer becomes a legitimate wholesale customer, *e.g.*, through municipalization, it would thereby become eligible to use the non-discriminatory open access tariffs we are proposing to require public utilities to provide. If costs are stranded as a result of this wholesale transmission access, we believe that these costs should be viewed as ''wholesale stranded costs.'' But for the ability of the new wholesale entity to reach another generation supplier through the FERC-filed open access transmission tariff, such costs would not be stranded. While the stranded costs likely would derive primarily from generation investments that previously were in retail rate base, we note that utilities generally build generating facilities and incur other costs to serve their entire load, both retail and wholesale. We believe that costs stranded by the departure of a retail-turned-wholesale customer could and should be considered FERC-jurisdictional stranded costs once the new wholesale customer begins taking wholesale transmission services. They are identifiable economic costs that were incurred by the jurisdictional transmitting utility, and they do not disappear simply because the identity of the customer changes from retail to wholesale. There is a clear nexus between the FERC-jurisdictional transmission and the exposure to non-recovery of prudently incurred costs. Accordingly, we believe this Commission should be the primary forum for addressing recovery of such costs. To avoid forum shopping and duplicative litigation of the issue, we expect parties to raise claims before this Commission in the first instance.

To implement this policy, we propose to change the definition of ''wholesale stranded costs'' that was contained in the initial NOPR, and to propose a definition that includes stranded costs resulting from unbundled wholesale transmission for newly created wholesale customers. We seek comment on this proposed change.

We propose to require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer or a retail customer that obtains retail wheeling as that required when wholesale requirements customers leave a utility's system. In this regard, we no longer propose to adopt the proposal in the initial NOPR that the ''reasonable expectation'' test should not apply in the case of retail-turned-wholesale customers or retail customers that obtain retail wheeling.[296] We propose that the utility must demonstrate that it incurred stranded costs based on a reasonable expectation that the customers would continue to receive bundled retail service. We expect that the reasonable expectation test would be easily met in those instances in which state law awards exclusive service territories and imposes a mandatory obligation to serve.[297] We solicit comments on this proposed change.

We reaffirm our proposal in the initial NOPR that utilities will have to make an evidentiary showing that the stranded costs are not more than the net revenues that retail-turned-wholesale customers or retail customers that obtain retail wheeling would have contributed to the utility had they remained retail customers of the utility, and that it has taken and will take reasonable steps to mitigate stranded costs. If the state has permitted any recovery from departing retail-turned-wholesale customers, we will deduct that amount from what we determine to be legitimate stranded costs for which we will allow recovery.

The procedures that we propose for a wholesale customer to file with the public utility when it requests computation of its stranded cost exposure will apply with equal force to a retail customer contemplating becoming a wholesale transmission customer (*e.g.*, through municipalization). In particular:

(1) Such a retail customer or group of customers may, at any time, request the public utility to either: (i) Calculate its maximum possible stranded cost exposure without mitigation, as of the date set forth in the customer's request; or (ii) provide the formula that the utility would use to calculate the customer's maximum possible stranded cost exposure without mitigation, to enable the customer to assess whether to become a wholesale transmission customer. The customer should specify in its request, to the extent possible, the date on which the customer would become a wholesale transmission customer of the utility and the amount of generation, if any, it will continue to purchase from its existing supplier. The customer may seek further information on how the stranded cost charge would vary as a result of choosing different dates or different amounts of substitute purchases. The customer also should indicate its preferred payment method(s) (*e.g.*, a monthly or annual adder to its transmission rate or an up-front lump-sum payment).

(2) The utility shall, within thirty days of receipt of the request, or other mutually agreed upon period, provide to the customer: (i) The customer's maximum possible stranded cost exposure without mitigation; or (ii) the formula that the utility would use to calculate the customer's maximum possible stranded cost exposure without mitigation. The utility's response should indicate the period over which the utility proposes to charge the departing customer. There should be appropriate support for each element in the calculation or formula to enable the customer to understand the basis for the element. The utility should provide a detailed rationale for its proposal as to how long the utility reasonably expected to keep the customer. The utility also should address how it intends to mitigate stranded costs.

(3) If the customer believes that the utility has failed to establish that it had a reasonable expectation of continuing to serve the customer or that the proposed maximum stranded cost charge without mitigation (or formula) is unreasonable, it will have thirty days in which to respond to the utility explaining why it disagrees with the charge. The parties should then attempt to reach a mutually-agreeable charge for stranded costs within a reasonable period.

(4) If the parties are unable to resolve the matter pursuant to the procedures specified in (1)–(3) above, the customer may either: (a) File a complaint with the Commission under section 206 of the FPA to seek a Commission determination whether the utility has met the reasonable expectation standard and, if so, whether the proposed maximum stranded cost charge (or formula) satisfies the other evidentiary standards set forth in this rule;[298] or (b) wait until the proposed stranded cost charge is filed under section 205 of the FPA, and contest it at that time. In either case, *i.e.*, a section 205 or 206 proceeding, the utility would only be able to seek stranded cost recovery according to the formula and other terms identified in its earlier discussions with the customer.

(11) State Mechanisms to Address Stranded Costs Caused By Retail Wheeling. The initial NOPR set forth a number of mechanisms that the Commission believes states can use to address stranded costs caused by retail wheeling and retail-turned-wholesale customers. We suggested that a state that permits a retail franchise customer to become a wholesale entity may consider whether to impose an exit fee prior to, or as a condition of, creating the wholesale entity.[299] We also suggested that a state may consider whether to require payment of an exit fee prior to a franchise customer being permitted to obtain unbundled retail wheeling. We noted that, in situations in which local distribution facilities are used by a retail wheeling customer, the state may consider whether to allow recovery of stranded costs through rates for local distribution services. Further, if a state decides not to impose an exit fee, or a surcharge through distribution rates, it may consider whether to allow recovery of stranded costs from remaining retail customers or whether shareholders should bear all or part of those costs.

We further suggested the possibility that state condemnation proceedings will provide a forum for a utility to seek recovery of any stranded costs where a new wholesale entity obtains ownership or control of a franchise utility's transmission or distribution facilities. The Commission solicited comments on other mechanisms that states can use to determine whether to allow stranded cost recovery, and from whom to allow recovery, and whether those mechanisms are adequate to deal with retail stranded costs.

(a) Comments. We note, as an initial matter, that many of the state commission commenters did not specifically respond to our questions concerning mechanisms available to the states for addressing stranded costs. Those that did, such as NARUC, the Texas Commission and the Vermont Department, however, agree that the states have a variety of mechanisms available to deal with stranded costs. In addition to the mechanisms that we identified in the initial NOPR (*i.e.*, imposing an exit fee prior to, or as a condition of, creating the wholesale entity; requiring an exit fee before a franchise customer is permitted to obtain unbundled retail wheeling; imposing a surcharge on local distribution rates; or state condemnation proceedings), these commenters identified the following: (1) Avoiding stranded costs in the first instance by seeking to preserve the integrity of the

[296] Stranded Cost NOPR at 32,879.

[297] We note, however, that certain states do not have service territories or have non-exclusive service territories (*e.g.*, Louisiana).

[298] If a complaint is filed, neither the customer nor the utility could raise issues not identified in their earlier discussions.

[299] Stranded Cost NOPR at 32,878.

utility's franchised service territory;[300] (2) seeking to reduce the burden of uneconomic costs through accelerated depreciation, revaluing of assets, or adjusting returns during the transition period; (3) allowing utilities to charge discounted rates (*i.e.*, below embedded cost but above marginal cost) or reforming retail rates through new rate methodologies such as performance-based pricing or price caps; (4) charging access fees to generating entities seeking to enter retail markets; (5) adopting tax-based solutions, such as credits or deductions; (6) requiring utility write-offs of uneconomic costs; (7) establishing a stranded cost recovery fund to be funded through a broad-based surcharge or a tax on retail market participants; (8) encouraging research and development of more efficient end-use electrical technologies; and (9) not guaranteeing service to a departing customer that seeks to resume retail service if capacity is unavailable when the customer seeks to return. NARUC suggests that these options are not mutually-exclusive, but instead could be used in combination with others depending on the particular circumstances.

In response to our question whether these mechanisms are adequate to deal with retail stranded costs, NARUC submits that the states have adequate legal authority to impose any existing regulatory mechanisms or to enact new mechanisms that may be needed to address stranded cost issues. NARUC further states that whether these mechanisms are adequate to provide utilities firm assurance that stranded costs will be recovered is not relevant to the Commission's inquiry. It argues that whether a utility in a particular case recovers all or part of what it identifies as stranded retail costs should be a fact-based determination made by the appropriate state commission(s).

(b) Preliminary Findings. We are satisfied that the states do have a number of mechanisms available to them to address stranded costs that result from retail customers who obtain retail wheeling, in order to reach a different generation supplier.[301] We encourage the states to use the mechanisms available to them in whatever way they deem appropriate to address stranded costs.

(12) Commission Authority to Regulate Transmission Rates, Terms, and Conditions for Unbundled Retail Transactions and Definition of State Jurisdictional Local Distribution. In the NOPR, the Commission stated that it has exclusive jurisdiction over the rates, terms and conditions of unbundled retail interstate transmission services. We based our conclusion in that regard on the plain meaning of the FPA and noted that there is nothing in the statute, the legislative history, or the case law to indicate that the Commission's jurisdiction over the rates, terms and conditions of transmission in interstate commerce extends only to wholesale transmission and not to retail transmission.[302] In the initial NOPR, we left open the question of the jurisdictional line between Commission- jurisdictional ''transmission'' and state-jurisdictional ''local distribution.'' However, as discussed, we believe it is appropriate to set forth our views in this document on the demarcation of our respective authorities in this regard.

(a) Comments. Some commenters note that the Commission's authority to regulate sales for resale and transmission of electric energy in interstate commerce is premised on Congressional intent to fill the ''Attleboro gap.'' These commenters note that Congress enacted the FPA to complement, not diminish, state authority. In light of this complementary jurisdictional posture, several commenters believe the Commission must explain how an unbundled retail sale is different from a bundled retail sale, which state commissions have regulated and will continue to regulate.

Various non-investor-owned utility commenters, including the Illinois Commission and NASUCA, maintain that the Commission does not have jurisdiction over transmission service for an unbundled retail transaction. NARUC maintains that the issue is, at the very least, unsettled. Therefore, before addressing the question of whether and how the Commission has jurisdiction over retail stranded costs, these commenters argue that the Commission should first re-examine whether its jurisdictional premise is correct, or simply convenient. Investor-owned utility commenters, on the other hand, generally concur with the conclusions in the NOPR regarding Commission jurisdiction.

The Illinois Commission maintains that this Commission's jurisdiction extends only to the transmission of electricity between utility systems. It fails to see how ''unbundling'' of generation service from transmission/distribution services, in order to effectuate ''retail wheeling,'' changes the basic intrastate nature of such services. The Illinois Commission states that if unbundled retail transmission is within the scope of federal jurisdiction, then one may question why the retail transmission portion of bundled services would not also be subject to Commission jurisdiction. It maintains that there is no legal or policy foundation supporting Commission jurisdiction over either bundled or unbundled retail electric services.

The Illinois Commission further argues that the case law relied upon in the NOPR fails to establish that the Commission has retail wheeling ratemaking authority. The Illinois Commission contends that each of the cases cited by the Commission (as well as the FPA itself) all predate the issues of retail wheeling and retail stranded costs. Thus, according to the Illinois Commission, the courts have never contemplated retail wheeling or the effects that retail wheeling would have in terms of stranded costs for public utilities or transmission carriers. The Illinois Commission argues that, because section 201(a) of the FPA prohibits infringement of Federal regulation on matters subject to regulation by the states and because states currently regulate bundled retail transmission, the Commission is necessarily precluded by the FPA from regulating retail transmission.

The Illinois Commission notes that under the Natural Gas Act, the states, and not the Commission, determine the rates, terms, and conditions of unbundled retail transportation services provided by local distribution companies. The Illinois Commission recommends that the Commission apply to the electric industry the same policy that it has adopted concerning its regulation of the gas industry and leave unbundled retail service regulation to state authorities.

Notwithstanding the jurisdictional debate, other state commission commenters such as the Ohio Commission contend that Commission assertion of jurisdiction may chill state willingness to undertake competitive reform at a retail level.[303] These

[300] The Texas Commission suggests, for example, that a state might limit certain forms of retail competition, such as retail wheeling or multiple certification in utility service areas.

[301] As discussed above, we have determined that we will address stranded costs caused by retail-turned-wholesale customers.

[302] Stranded Cost NOPR at 32,876–77.

[303] The Ohio Commission proposes a model for drawing the line of demarcation between federal and state jurisdiction whereby the states would have rate jurisdiction over the wheeling-in portion of unbundled retail service (*i.e.*, the point at which retail power enters the system of the last entity who redelivers the power to the end-use customer) and this Commission would retain jurisdiction over the wheeling-out and wheeling-through portions of a transaction. It contends that retention of

commenters further contend that Commission intervention in retail ratemaking will undermine a state's ability to address retail issues without being ''second guessed.'' Commenters view this regulatory uncertainty as an unwarranted and unnecessary result of the Commission's purported invalid assumption of jurisdiction.

(b) Commission Ruling. We reaffirm our legal conclusion that the Commission has jurisdiction over the rates, terms and conditions of unbundled interstate transmission services by public utilities to retail customers, and that we have the authority to address retail stranded costs through our jurisdiction over such services.

However, we also believe the States have authority to address retail stranded costs through their jurisdiction over facilities used in local distribution.[304] It is therefore important to define what we believe to be the legal demarcation between ''transmission in interstate commerce'' and ''local distribution,'' as used in the FPA. In addition, this demarcation is important because of the consequences it will have for the public utility facilities that will be affected by the open access requirements being proposed. We set forth below our jurisdictional analysis, and technical factors, for determining what constitutes ''facilities used in local distribution.''

(13) Stranded Costs in the Context of Voluntary Restructuring. As we note in the Open Access NOPR, the functional unbundling of wholesale services that we are proposing does not require corporate unbundling (disposition of assets to a non-affiliate, or establishing a separate corporate affiliate to manage a utility's transmission assets) in any form. At the same time, we recognize that some utilities may ultimately choose such a course of action. The Commission is willing to consider case-specific proposals for dealing with stranded costs in the context of any restructuring proceedings that may be instituted by individual utilities.

G. Transmission/Local Distribution

In light of the proposals in both the Open Access NOPR and the Stranded Cost Supplemental NOPR, the Commission believes it is important to express its views on the distinction between Commission-jurisdictional transmission in interstate commerce, and state-jurisdictional local distribution, in the context of unbundled wheeling by public utilities.[305] The distinction is important for three reasons. First, facilities that can be used for wholesale transmission in interstate commerce would be subject to the Commission's open access requirements. It is important that public utilities and their customers have a good understanding of which facilities will be subject to such requirements. Such understanding will be crucial to appropriate planning as we enter into the competitive regime. It is also important that utilities not be able to shield themselves from the Commission's open access requirements by claiming that the facilities necessary to deliver power to a wholesale purchaser are non-jurisdictional ''local distribution'' facilities.

Second, as discussed *supra,* states may, through their jurisdiction over facilities used in local distribution, impose a surcharge on local distribution that will permit recovery of stranded costs resulting from retail wheeling or retail-turned-wholesale customers. Providing guidance on the demarcation between transmission and local distribution should assure States that they have the ability to assess stranded costs on the departing customers. This should result in more realistic economic evaluations by retail customers contemplating leaving via retail wheeling and/or municipalization.

Third, as the structure of the electric industry continues to change dramatically, particularly with the wide availability of unbundled wholesale (and perhaps retail) services to deliver power and the potential for various forms of voluntary corporate unbundling, utilities need to know which regulator has jurisdiction over which facilities in order to meet State and Federal statutory filing requirements.

Two specific circumstances are addressed:

First, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

Second, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier directly to an end user?

Based on an analysis of the relevant legislative history and case law under the FPA, the Commission reaches the following conclusions. With respect to the first circumstance, the Commission concludes that a public utility's facilities used to deliver electric energy to a wholesale purchaser, whether labeled ''transmission,'' ''distribution,'' or ''local distribution'' are subject to the Commission's exclusive jurisdiction under sections 205 and 206, and that a public utility's facilities used to deliver electric energy from the wholesale purchaser to the ultimate consumer are ''local distribution'' facilities subject to the rate jurisdiction of the state.[306]

With respect to the second circumstance, the Commission believes that, based on the particular facts of the case, some of the public utility's facilities used to deliver electric energy to an end-user may be FERC-jurisdictional transmission facilities, while some of the facilities used may be state-jurisdictional local distribution facilities.

We set forth below the relevant legislative history and case law, our legal conclusions, and the factors which we believe are indicative of whether facilities are used in ''local distribution'' or ''transmission in interstate commerce,'' as those terms are used in the FPA.

1. Relevant Federal Power Act (FPA) Provisions

The Commission's jurisdiction is set forth in section 201 of the FPA.[307] Section 201(b)(1) provides in pertinent part:

The provisions of this Part shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce * * *. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction * * * over *facilities used in local distribution* or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[308]

Section 201(c) provides that:

---

jurisdiction over a portion of wheeling is necessary for states to be able to assess retail stranded costs.

[304] States also have the authority to address so-called ''stranded benefits'' (*e.g.*, environmental benefits associated with conservation, load management and other DSM programs) through their jurisdiction over local distribution.

[305] The term ''wheeling'' is intended to cover any delivery of electric energy from a supplier to a purchaser, *i.e.*, transmission, distribution, and/or local distribution. The Commission also has jurisdiction to order wholesale transmission services in either interstate or intrastate commerce by transmitting utilities that are not also public utilities. See *Tex La Electric Cooperative of Texas, Inc.*, 67 FERC ¶ 61,019 (1994), *reh'g pending.*

[306] There are, of course, facilities that are used to provide delivery to both wholesale purchasers and end users. In those situations, we believe that the Commission and the States have jurisdiction to set rates for the services that are within their respective jurisdictions. That facilities are used to serve resale and retail customers does not, however, necessarily mean that the facilities are local distribution facilities.

[307] 16 U.S.C. 824.

[308] 16 U.S.C. 824(b) (emphasis added).

electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.[309]

Some of the court decisions that construe jurisdictional facilities under section 201 also construe the Commission's jurisdiction under section 203. Section 203(a) provides, in relevant part:

No public utility shall sell, lease, or otherwise dispose of the whole of its *facilities subject to the jurisdiction of the Commission*, * * * or by any means whatsoever, directly or indirectly, merge or consolidate such facilities or any part thereof with those of any other person * * * without first having secured an order of the Commission to do so.[310]

In addition, section 206(d) concerns facilities ''under the jurisdiction of the Commission'':

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of *facilities under the jurisdiction of the Commission* in cases where the Commission has no authority to establish a rate governing the sale of such energy.[311]

2. Legislative History of the FPA

The relevant legislative history of the general purposes of Title II of the FPA, and of section 201 in particular, focuses primarily on bundled sales of electric energy and does not directly address the issue of what constitutes local distribution as opposed to transmission in interstate commerce.

In discussing the general purposes of Title II of the House bill, the House Report states:

Title II * * * establishes for the first time regulation of electric utility companies transmitting energy in interstate commerce.

* * * * *

* * * Under the decision of the Supreme Court of the United States in *Public Utilities Commission* v. *Attleboro Steam & E. Co.* (273 U.S. 83 [(1927)]) [(*Attleboro*)], the rates charged in interstate wholesale transactions may not be regulated by the States. Part II gives the Federal Power Commission jurisdiction to regulate these rates. A ''wholesale'' transaction is defined to mean the sale of electric energy for resale and the Commission is given no jurisdiction over local rates even where the electric energy moves in interstate commerce.[312]

In its analysis of section 201, the House Report states:

As in the Senate bill no jurisdiction is given over local distribution of electric energy, and the authority of States to fix local rates is not disturbed even in those cases where the energy is brought in from another State.[313]

The Senate Report's discussion of the general purposes of the FPA states:

The decision of the Supreme Court in [*Attleboro*] placed the interstate wholesale transactions of the electric utilities entirely beyond the reach of the States. Other features of this interstate utility business are equally immune from State control either legally or practically.[314]

In discussing material differences between the final version of the Senate bill and the original version, the Senate Report states:

Subsection (b), formerly (a), which states the subject matter to which the part relates, has been clarified to make plain that it includes interstate transmission where there is no sale and excludes all facilities used only for production of transmission in intrastate commerce or in local distribution.[315]

In discussing section 201 of the Senate bill, the Senate Report further states:

The rate-making powers of the Commission are confined to those wholesale transactions which the Supreme Court held in [*Attleboro*] to be beyond the reach of the States. Jurisdiction is asserted also over all interstate transmission lines whether or not there is sale of the energy carried by those lines and over the generating facilities which produce energy for interstate transmission and sale. It is obvious that no steps can be taken to secure the planned coordination of this industry on a regional scale unless all of the facilities, other than those used solely for retail distribution, are made subject to the jurisdiction of the Commission. Facilities used only for intrastate commerce or local distribution are expressly excluded from the operation of the act.[316]

The Conference Report adds little description regarding jurisdictional facilities. In reference to section 201(b) it states that:

[T]he language of the House amendment has been followed with a clarifying phrase added to remove any doubt as to the Commission's jurisdiction over facilities used for the generation and local distribution of electric energy to the extent provided in other sections of this part and the part next following.[317]

In addition to the above statements pertaining to section 201 of the FPA, Congress referenced distribution of energy in the legislative history of section 206(d). Section 206(d) was originally enacted as section 206(b) of the FPA. Under the Regulatory Fairness Act of 1988,[318] section 206(b) was redesignated as section 206(d).

The Conference Report on the original FPA does not address section 206(b). The Senate Report on the FPA bill states in pertinent part:

Subsection (b) authorizes the Commission to investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy * * *. Since the rate-making powers granted to the Commission apply only to the wholesale rates of energy sold in interstate commerce, this last subsection should be of great benefit in removing the practical difficulty which the States may encounter in regulating the *interstate distribution rates* which are left under their control. Such rate regulation involves the examination and valuation of property *outside* the State. The task is one requiring an agency with a jurisdiction broader than that of a single State. The authority of the Federal Commission is to render assistance to the State commissions in a way which would preserve and make more effective the jurisdiction which is thus left to the States.[319]

The House Report discusses section 206(b) as follows:

This subsection reaches those situations where electric energy is transmitted in interstate commerce *by the same company which distributes it locally*, and will greatly aid State commissions in fixing reasonable rates in such cases.[320]

Thus, the discussions in the two reports do not appear to contemplate a situation in which the transmitter and seller of electric energy are different, and neither is a ''local'' distributor. The House Report expressly refers to the same company being the transmitter and seller of electric energy. The Senate Report by its terms addresses the regulation of interstate distribution rates.[321]

[309] 16 U.S.C. 824(c).

[310] 16 U.S.C. 824b (emphasis added).

[311] 16 U.S.C. 824e(d) (emphasis added).

[312] H.R. Rep. No. 1318, 74th Cong., 1st Sess. 7–8 (1935).

[313] *Id.* at 27.

[314] S. Rep. No. 621, 74th Cong., 1st Sess. at 17 (1935). See *id.* at 18 (''The revision [between the original and final versions of the Senate bill] has also removed every encroachment upon the authority of the States. The revised bill would impose Federal regulation only over those matters which cannot effectively be controlled by the States.'')

[315] *Id.* at 19.

[316] *Id.* at 48. The provisions of the Senate bill regarding federal jurisdiction over generating facilities were eliminated from the final version of the bill.

[317] H.R. Conf. Rep. No. 1903, 74th Cong., 1st Sess. 74 (1935).

[318] Pub. L. 100–473, 102 Stat. 2299 (1988).

[319] S. Rep. No. 621, 74th Cong., 1st Sess. 51 (1935) (emphasis added).

[320] H.R. Rep. No. 1318, 74th Cong., 1st Sess. 29 (1935) (emphasis added).

[321] The Senate Report states that interstate distribution rates are left in the States' control. Obviously, the Senate drew a distinction between interstate distribution (left in the States' control) and interstate transmission (given to the FPC). *Compare* S. Rep. No. 621 at 49 with H.R. Rep. No. 1318 at 51.

The above legislative history on sections 201 and 206(b) does not provide any definitive answers to the questions raised. We therefore turn to the case law under the FPA.

3. Case Law under the FPA

Jersey Central Power & Light Company v. *Federal Power Commission (Jersey Central)* [322] was the first of the major FPC jurisdictional cases considered by the Supreme Court. The case involved the acquisition by New Jersey Power and Light Company (New Jersey Power) of certain securities of Jersey Central Power & Light Company (Jersey Central) without the Commission's prior approval. The question before the Court was whether Jersey Central was a ''public utility'' under section 201(e) [323] of the FPA so that the Commission's prior approval of the stock acquisition was necessary under section 203 of the FPA.

Jersey Central owned transmission facilities that connected to facilities that Public Service Electric & Gas Company (Public Service) owned. The interconnection of these transmission facilities was in New Jersey. Public Service's facilities in turn connected to the facilities of the Staten Island Edison Corporation (Staten Island Edison), a New York utility, at the mid-channel of Kill van Kull, a body of water separating New Jersey and New York. Jersey Central delivered energy to and received energy from Public Service under contract, and Public Service delivered energy to and received energy from Staten Island Edison under contract.[324]

The Court found that, although Jersey Central generated and received electricity only in New Jersey, some of the electric energy that it dispatched to Public Service ''was instantaneously transmitted to New York.'' [325] The Court held that ''[t]his evidence * * * furnishes substantial basis for the conclusion of the Commission that facilities of Jersey Central are utilized for the transmission of electric energy across state lines.'' [326] Therefore, the Court found that Jersey Central was a public utility within the meaning of section 201(e).[327] The

The Court cited *Attleboro,* in which the Court found that the sale of locally produced electric energy for use in another state resulted in the transmission of electric energy in interstate commerce, even though title passed at the state line.[328] In *Jersey Central,* the Court explained the rationale for federal jurisdiction as follows:

> [Section 201(c) of the FPA] defines the electric energy in commerce as that ''transmitted from a State and consumed at any point outside thereof.'' There was no change in this definition in the various drafts of the bill. The definition was used to ''lend precision to the scope of the bill.'' It is impossible for us to conclude that this definition means less than it says. * * * The purpose of this act was primarily to regulate the rates and charges of the interstate energy.[329]

The Court in *Jersey Central* thus interpreted the FPA as placing within the federal province regulation of wholesale sales of electric energy that, in any manner, flows in interstate commerce. The language quoted above and the citation to section 201(c) of the FPA, to be relied upon in subsequent Supreme Court cases, strongly suggested that the Commission's jurisdiction was not based on whether there was a sale by the utility, but rather on the flow of electric energy either into or out of a state, so long as the energy crosses state lines.

Connecticut Light & Power Company v. *Federal Power Commission (CL&P),*[330] which was decided two years after *Jersey Central,* is the leading case interpreting the section 201(b) local distribution proviso. In *CL&P,* the Commission sought to regulate the accounting practices of Connecticut Light & Power Company (*CL&P*).[331] At issue was whether *CL&P* was a ''public utility'' under the FPA. The utility's system encompassed an area solely within a single state (Connecticut) [332] and did not interconnect with any other company that operated out of state.[333] ''Its purchases and sales, its receipts and deliveries of power, [were] all within the state.'' [334] However, CL&P did purchase energy from companies that had, in turn, purchased energy from Massachusetts. The company also sold energy to a municipality that exported a portion of that energy to Fishers Island, located off the coast of Connecticut but ''territory of New York.'' [335] The Commission based its jurisdiction on these few transactions.[336]

The Court of Appeals affirmed the Commission, holding that the Commission's jurisdiction extended to ''electric distribution systems which normally would operate as interstate businesses.'' The Court of Appeals found that:

> whether or not the facilities by which petitioner distributes energy from Massachusetts should be classified as ''local'' is not relevant to this case. The sole test of jurisdiction of the Commission over accounts is whether these facilities, ''local'' or otherwise, are used for the transmission of electric energy from a point in one state to a point in another.[337]

The Supreme Court reversed. It held that the statutory language in section 201(b) of the FPA providing that the Commission ''shall not have jurisdiction * * * over facilities used in local distribution'' is a limitation upon Commission jurisdiction that ''the Commission must observe and the courts must enforce.'' [338] In analyzing the statute, the Court stated:

> It has never been questioned that technologically generation, transmission, distribution and consumption are so fused and interdependent that the whole enterprise is within the reach of the commerce power of Congress, either on the basis that it is, or that it affects, interstate commerce, if at any point it crosses a state line.
>
> * * * * *
>
> But whatever reason or combination of reasons led Congress to put the provision in the Act, we think it meant what it said by the words ''but shall not have jurisdiction * * * over facilities used in local distribution.'' Congress by these terms plainly was trying to reconcile the claims of federal and local authorities and to apportion federal and state jurisdiction over the industry.[339]]

The Court decided that this limitation on jurisdiction was ''a legal standard that must be given effect in this case in addition to the technological transmission test.'' [340]

The Court stated that whether or not local distribution facilities carried out-of-state electric energy was irrelevant. Whatever the origin of the electric energy they carried, so long as the utility used the lines for local

[322] 319 U.S. 61 (1943) *(Jersey Central).*

[323] Section 201(e) defines a ''public utility'' as ''any person who owns or operates facilities subject to the jurisdiction under this Part (other than facilities subject to such jurisdiction solely by reason of section 210, 211, or 212).'' 16 U.S.C. 824(e). The section as adopted in 1935 did not contain the parenthetical, which was adopted in 1978 as part of the Public Utility Regulatory Policies Act.

[324] *Jersey Central,* 319 U.S. at 63–65.

[325] *Id.* at 66.

[326] *Id.* at 67 (citation omitted).

[327] *Id.* at 73.

[328] 273 U.S. at 86, 89–90.

[329] 319 U.S. at 71 (footnote omitted).

[330] 324 U.S. 515 (1945) (*CL&P*).

[331] *Id.* at 517.

[332] *Id.* at 518.

[333] *Id.* at 521.

[334] *Id.* at 522.

[335] *Id.* at 519–21.

[336] *Id.*

[337] *Id.* at 522, quoting *Connecticut Light & Power Co.* v. *FPC,* 141 F.2d 14, 18 (D.C. Cir. 1944).

[338] 324 U.S. at 529.

[339] *Id.* at 529–31.

[340] *Id.* at 531.

distribution,[341] they were exempt from federal jurisdiction. [342] In fact, the Court stated that local distribution facilities ''may carry no energy except extra-state energy and still be exempt under the Act.'' *Id.* at 531. The Court concluded that the Commission's order:

Must stand or fall on whether this company owned facilities that were used in transmission of interstate power and which were not facilities used in local distribution.[343]

Upon reversing the Court of Appeals, the Court commented, in dictum, on the evidence the Commission had relied upon in finding that the facilities in question were used for transmission. It noted that the Commission had relied upon certain gas transportation cases in concluding that transmission extends from the generator to the point where the function of conveyance in bulk over distance is completed and the process of subdividing the energy to serve ultimate consumers, which is the characteristic of ''local distribution,'' is begun. The Court cautioned:

But a holding that distributing gas at low pressure to consumers is a local business is not a holding that the process of reducing it from high to low pressure is not also part of such local business. In so far as the Commission found in these cases a rule of law which excluded from the business of local distribution the process of reducing energy from high to low voltage in subdividing it to serve ultimate consumers, the Commission has misread the decisions of this Court. No such rule of law has been laid down.[344]

The Court also noted in its dictum, however, that once a company is properly found to be a ''public utility'' under the Act, the fact that a local commission may also have jurisdiction does not preclude exercise of the Commission's functions. *Id.* at 533.[345]

The Court instructed the lower court to remand the case to the Commission for a finding regarding whether the facilities in question were used in local distribution.[346]

The *CL&P* case was ultimately disposed of without the Commission having made a finding that the facilities were used in local distribution. While the Commission found that it was ''extremely doubtful'' that it could find that the facilities in question were not local distribution facilities, 6 FPC 104, 106 (1947), the Commission did not articulate a definition of local distribution facilities.

In *Wisconsin-Michigan Power Co.* v. *Federal Power Commission,* [347] the Seventh Circuit held that a utility was a jurisdictional public utility where it operated two divisions in Wisconsin and Michigan in a coordinated manner such that electric energy from one state was transmitted to the other, and vice versa, ''in appreciable amounts by the power company and by it commingled with energy generated in the two respective districts and then delivered to the [wholesale] customers.* * * '' [348] The court also rejected the notion that the energy changed its form or character when it was stepped down in voltage before it reached the wholesale purchasers.[349]

The court in *Wisconsin-Michigan* distinguished between transmission and local distribution by focusing on wholesale sales of electric energy versus retail sales (''local rates'') of electric energy. It cited the House Report on the FPA, and characterized the legislative history as follows:

The legislative history, [H.R. Rep. No. 1318], 74th Cong., 1st Sess. pages 7, 8 and 27 [(1935)], discloses that the Congressional Committee intended that *the provisions of the [FPA] should apply to the transmission of electric energy in interstate commerce, i.e., the sale of energy at wholesale in interstate commerce, but not to the retail sale of any such energy in local distribution;* that the [FPA] left to the state the authority to fix local rates where the energy is brought in from other states, and that the rate making power of the [FPC] was to be confined to those *wholesale transmissions* which the Supreme Court had held in [*Attleboro*] to be beyond the reach of the state. Under that decision, said the committee, the rates charged in interstate wholesale transactions could not be regulated by the states. It defined a wholesale transaction as the sale of electric energy for resale.[350]

The Seventh Circuit's characterization of the House Report seems to equate transmission of electric energy in interstate commerce with the sale of energy at wholesale in interstate commerce. However, this interpretation is at odds with both the plain words of the statute as well as the language of the House Report, both of which refer to transmission in interstate commerce separately from sales for resale in interstate commerce.[351] In addition, the Senate Report, which the Seventh Circuit did not mention, clearly recognized jurisdiction over all interstate transmission lines, whether or not a sale of energy is carried by those lines.[352]

The *Wisconsin-Michigan* court also cited analogous natural gas cases, stating that ''[t]he question is essentially, when does interstate commerce transportation end and where does the local distribution facilities first become operative.''[353] The court further stated that:

[U]pon delivery to [the wholesaler] local distribution begins when he resells. His sales and distribution at retail are clearly local in character, and constitute only local distribution; but at no point before delivery to him has been completed, has interstate transmission terminated. In other words, ''facilities used in local distribution'' means facilities used for making resale and distribution to consumers, jurisdiction over which is left to the states. It was only because of this conclusion that the Supreme Court said, [citation omitted], the Act ''cut[s] sharply and cleanly between sales for resale and direct sales for consumptive uses.'' We think there is no ground for the position that local distribution includes any transmission occurring before the wholesaler who resells at retail is reached. [354]

The Seventh Circuit concluded that the sales for resale were made in interstate commerce; that local distribution had not begun; that the interstate character of the transmission persisted until delivery to the wholesaler; that, up to that point, no

[341] It appears that while the Company received power (at one location) at 66 kV, it primarily owned facilities at 13.8 kV and below.

[342] 324 U.S. at 531.

[343] *Id.* at 531 (emphasis added).

[344] *Id.* at 534.

[345] See *United States* v. *Public Utilities Commission of California,* 345 U.S. 295, 316 (1953) (Public Utilities Commission):

Certainly the concrete fact of resale of some portion of the electricity transmitted from a state to a point outside thereof invokes federal jurisdiction at the outset, despite the fact that the power thus used traveled along its interstate route ''commingled'' with other power sold by the same seller and eventually directly consumed by the same purchaser-distributor.

See also *Arkansas Power & Light Co.* v. *FPC,* 368 F.2d 376, 383 (8th Cir. 1966) (''Where a company is in fact a public utility, all wholesale sales for resale in interstate commerce are subject to the provisions of sections 205 and 206 of the [FPA], regardless of the facilities used.''). The Eighth Circuit further noted that the section 201(b) exemption applies to a company's status as a public utility and not to the Commission's jurisdiction over sales in interstate commerce for resale. *Id.,* citing *Public Utilities Commission, Colton, infra,* and *Wisconsin-Michigan, infra.*

[346] *Id.* at 536.

[347] 197 F.2d 472 (7th Cir. 1952), cert. denied, 345 U.S. 934 (1953) (Wisconsin-Michigan).

[348] Id. at 474.

[349] Id. (''Obviously the energy thus transmitted in interstate commerce is not changed in form or in character except that the voltage is reduced to an extent consistent with efficient economic management and operation.'').

[350] 197 F.2d at 476 (emphasis added).

[351] See H.R. Rep. No. 1318 at 27. (''Subsection (b) confers jurisdiction upon the Commission over the transmission of electric energy in interstate commerce and the sale of electric energy in wholesale in interstate commerce* * *'' emphasis added).

[352] See S. Rep. No. 621 at 48 (''Jurisdiction is asserted over all interstate transmission lines whether or not there is a sale of the energy carried by those lines * * *'').

[353] 197 F.2d at 477.

[354] *Id.*, citing *FPC* v. *East Ohio Gas Co.*, 338 U.S. 464 (1950) (East Ohio).

local distribution facilities were in operation and that, therefore, the sales were subject to Commission regulation.

In *Federal Power Commission* v. *Southern California Edison Company* (the *Colton* case),[355] the Supreme Court held that the FPA provides a clear line of demarcation between jurisdictional transactions and non-jurisdictional transactions. However, this case, too, involved bundled sales of electric energy. In the facts of the case, Southern California Edison Company (Edison) admitted that it was a public utility by virtue of owning two interstate transmission lines.[356] At issue was whether its sales of electric energy to the City of Colton, California, for resale to Colton's retail customers, were jurisdictional. Included in the electric energy that Edison sold to Colton was out-of-state electric energy from Hoover Dam.[357] The Commission ruled that the sale to Colton was a sale of electric energy at wholesale in interstate commerce subject to regulation under the FPA.[358] In upholding the Commission, the Court held that Edison's importation of out-of-state electricity for resale to Colton sufficed to confer Federal jurisdiction.

The Court, citing an earlier Supreme Court case,[359] characterized Congressional intent in the FPA:

> [W]hat Congress did was to adopt the test developed in the *Attleboro* line which denied state power to regulate a sale ''at wholesale to local distributing companies'' and allowed state regulation of a sale at ''local retail rates to ultimate consumers.'' [360]

The Court rejected the argument that FPC jurisdiction was confined to those interstate wholesale sales constitutionally beyond the power of State regulation by force of the Commerce Clause, and was to be determined on a case-by-case analysis of the impact of state regulation upon the national interest. The Court stated that in the FPA:

> [C]ongress meant to draw a bright-line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis. This was done in the Power Act by making FPC jurisdiction plenary and extend[ed] it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States. [361]

The Court held that ''[t]here is no such exception covering the Edison-Colton sale.'' [362]

Parties in the Colton case had raised the question of whether jurisdiction over the Colton sale was prevented by the ''local distribution'' proviso of section 201(b). The Court stated that whether facilities are local distribution facilities is a matter for the Commission to decide in the first instance. Citing *CL&P, supra,* it stated:

> Whether facilities are used in local distribution—although a limitation on FPC jurisdiction and a legal standard that must be given effect in addition to the technological transmission test . . . —involves a question of fact to be decided by the FPC as an original matter. [363]

The Court cited evidentiary support and the Commission's expertise in such matters in upholding the Commission's determination that certain facilities owned by Edison were used exclusively to effect the wholesale sale to Colton and not for local distribution. Such facilities included 12 kV lines that served an industrial customer, several lighted highway signs, a residence and a railroad section house before they reached the transformers in the Colton substation. The FPC had held that those uses prior to the lines reaching the Colton substation did not transform the lines into local distribution facilities.[364]

In *Duke Power Company* v. *Federal Power Commission (Duke),* [365] the D.C. Circuit held that a public utility's acquisition of facilities used solely in local distribution, and which would continue to be used for local distribution, was beyond the Commission's jurisdiction under section 203. The case involved Duke Power Company's (Duke's) proposed acquisition of facilities owned by Clemson University (Clemson), which were used to distribute electricity off-campus to customers (primarily university personnel) in two South Carolina counties. Clemson purchased the power at wholesale from Duke. No one appeared to contest the conclusion that the 7 miles of distribution line and 418 service connections owned by Clemson were ''local distribution'' facilities.[366] Rather, the case turned on interpreting section 203 and whether it was intended to affect only acquisitions of jurisdictional facilities, or also to affect acquisitions of non-jurisdictional facilities. In interpreting section 203, however, the D.C. Circuit extensively analyzed and discussed the fundamental jurisdictional lines that Congress drew in section 201.

Citing to the CL&P case, the court in Duke stated:

> The Act, as we have seen, effectuated federal control over the transmission and the sale at wholesale of electric energy in interstate commerce, and established the Commission's regulatory power over public utilities engaging in either of these pursuits.[367]

However, quoting *CL&P,* the court further stated:

> The expression ''facilities used in local distribution'' is one of relative generality. But as used in this Act it is not a meaningless generality in the light of our history and the structure of our government. We hold the phrase to be a limitation on jurisdiction and a legal standard that must be given effect in this case in addition to the technological transmission test.[368]

The court further rejected the Commission's concept that, in order to determine whether jurisdiction over any particular acquisition existed, the impact of local supervision be measured on a case-by-case basis. Quoting from *Colton,* the court stated:

> [T]his ''flexible approach''—involving as it does the consideration, inter alia, of ''the effect of the regulation upon the national interest in the commerce''—has been flatly rejected as a technique for resolving jurisdictional conflicts between the Commission and state bodies * * * We think that like the line ''[i]t cut sharply and cleanly between sales for resale and direct sales for consumptive uses'' to facilitate jurisdictional determinations in rate regulation, ''Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis,'' in distributing regulatory power over the acquisition of facilities.[369]

The court rejected the Commission's argument that jurisdiction over the merger or consolidation of jurisdictional facilities with those of any other ''person'' under section 203 gave the Commission jurisdiction over Duke's acquisition. The court stated that the FPA reflects a policy '''that matters largely of a local nature, even though

[355] 376 U.S. 205 (1964) (*Colton*).

[356] The Supreme Court noted that Edison's status as a public utility did not decide the question of whether the FPC could assert jurisdiction over the rates for the Edison-Colton sale. *Id.* at 208 n.3.

[357] *Id.* at 208, 209 & n.5.

[358] *Id.* at 208. See *Arkansas Electric Cooperative Corp.* v. *Arkansas Public Service Commission*, 461 U.S. 375, 380 (1983) (''[Colton] held, among other things, that * * * a California utility that received some of its power from out-of-State was subject to Federal and not State regulation in its sales of electricity to a California municipality that resold the bulk of the power to others.'').

[359] *Illinois Natural Gas Co.* v. *Central Illinois Public Service Co.,* 314 U.S. 498, 504 (1942).

[360] 376 U.S. at 214.

[361] *Id.* at 215–216.

[362] *Id.* at 216 (footnote omitted).

[363] *Id.* at 210 n.6 (citation omitted).

[364] *Id.* at 210 n.6.

[365] 401 F.2d 930 (D.C. Cir. 1968) (*Duke*).

[366] Duke delivered power to Clemson at a distribution voltage of 4,160 volts. The step-down transformers by which the voltage was reduced, and the substations at which the delivery was effected, were owned by Duke. 401 F.2d at 931, n.8.

[367] 401 F.2d at 938–39 (emphasis added, footnotes omitted).

[368] Id. (footnote omitted).

[369] *Id.* at 949 (footnotes omitted).

interstate in character, should be handled locally and should receive the consideration of local [officials] familiar with the local conditions in the communities involved.''[370]

Federal Power Commission v. *Florida Power & Light Company* [371] is the last major court case to address the Commission's transmission jurisdiction. In this case, the Commission sought to impose its accounting rules upon Florida Power & Light Company (Florida Power & Light). The company's system lay solely within the borders of Florida and did not directly connect with any out-of-state utility.[372] The Commission held that Florida Power & Light did own facilities that transmitted electric energy in interstate commerce, but the Court of Appeals for the Fifth Circuit ruled that the Commission did not have substantial evidence to support its finding.

The Supreme Court reversed. The Supreme Court noted that Florida Power & Light was a member of the Florida Power Pool along with Florida Power Corporation (Florida Power Corp.).[373] In turn, Florida Power Corp. connected with Georgia Power Company (Georgia Power) at a ''bus'' [374] south of the Georgia-Florida border.[375] Florida Power Corp. regularly exchanged power with Georgia Power.[376] In many instances, Florida Power Corp. transferred power to Florida Power & Light instantly after receiving power from Georgia Power, and transferred power to Georgia Power immediately after receiving power from Florida Power & Light.[377] The Supreme Court found that power commingled in the bus moved across state lines, and concluded that Florida Power & Light engaged in transmission in interstate commerce. The Court held that, to establish jurisdiction, the Commission need only show that ''some [Florida Power & Light] power goes out of State.'' [378] The Court further explained that ''[i]f any [Florida Power & Light] power has reached Georgia, or [if Florida Power & Light] makes use of any Georgia power * * * FPC jurisdiction will attach * * *.'' [379]

There is also a line of cases that address, among other things, what constitutes a Commission jurisdictional ''sale of electric energy at wholesale'' [380] under section 201 of the FPA.[381] These cases all concerned bundled sales. While the issues posed above involve unbundled wheeling, the ''resale'' cases are helpful to the extent they suggest that local distribution takes place only after power is subdivided. See, *e.g.*, 345 U.S. at 316 (''the facilities supplied 'local distribution' only after the current was subdivided for individual consumers.'').

4. Natural Gas Act

The Natural Gas Act (NGA) was adopted in 1938. Like the FPA, the NGA contains language limiting the Commission's jurisdiction in situations involving local distribution.[382]

Section 1(b) of the NGA provides:

> The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural gas companies engaged in such transportation or sale, *but shall not apply* to any other transportation or sale of natural gas or *to the local distribution of natural gas or to the facilities used for such distribution* or to the production or gathering of natural.[383]

There is similarity in many respects between the House and Senate Reports on the FPA and the NGA with respect to the jurisdiction given the Commission. For example, all four reports mention *Attleboro* as placing interstate wholesale transactions beyond the reach of the States. As indicated in the House Report on the NGA, the States could ''regulate sales to consumers even though such sales are in interstate commerce, such sales being considered local in character and in the absence of congressional prohibition subject to State regulation.'' (See H.R. Rep. No. 709, 75th Cong., 1st Sess. 1). However, the House and Senate Reports on the NGA contain identical language not found in the reports on the FPA:

> In view of the importance of section 1(b), which states the scope of the act, it seems advisable to comment on certain provisions appearing therein. It will be noted that this subsection of the bill, after affirmatively stating the matters to which the act is to apply, contains a provision specifying what the act is not to apply to, as follows:
>
> But shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.
>
> *The quoted words are not actually necessary,* as the matters specified therein could not be said fairly to be covered by the language affirmatively stating the jurisdiction of the Commission, but similar language was in previous bills, and, rather than invite the contention, however unfounded, that the elimination of the negative language would broaden the scope of the act, the committee has included it in this bill. *That part of the negative declaration stating that the act shall not apply to ''the local distribution of natural gas'' is surplusage by reason of the fact that distribution is made only to consumers in connection with sales, and since no jurisdiction is given to the Commission to regulate sales to consumers the Commission would have no authority over distribution, whether or not local in character.* (Emphasis added). [[384]]

As a result of this language it can be argued that Congress considered distribution (and local distribution) only in the context of bundled retail sales of natural gas. In fact, it appears that all of the court cases affirming the states' right to regulate local distribution of gas have involved bundled retail sales. See *Panhandle Eastern Pipe Line Co.* v. *Michigan Public Service Commission,* 341 U.S. 329 (1951) *(Panhandle).* There the Court, in affirming the State of Michigan's right to regulate an interstate pipeline's proposed bundled retail sales of gas to industrial consumers, noted that the pipeline company proposed to lay pipeline in ''the streets and alleys of Detroit'' and ignored the local distribution company's request for additional gas to meet the increased needs of the industrial consumers. *Id.* at 333. While the Court based its holding on a state's authority to regulate direct (retail) sales to an end-user, rather than on the basis of the section 1(b) local distribution provision, it also found that the proposed sales were ''primarily of local interest'' and ''emphasized the need for local regulation.'' *Id.* Two years before *Panhandle,* the Supreme Court issued its decision in *FPC* v. *East Ohio Gas Co.,* 338 U.S. 465 (1949) *(East Ohio).* East Ohio Gas Company owned and operated a natural gas business wholly within the State of Ohio. The company sold gas only to Ohio customers but most of the gas was transported to Ohio from other states by interstate pipelines. These interstate

---

[370] *Id.* at 936 (quoting from Hearings on H.R. 5423 before the House Committee on Interstate and Foreign Commerce, 74th Cong., 1st Sess. 393 (1935) (testimony of then-FPC Commissioner Seavey)).

[371] 404 U.S. 453, *reh'g denied*, 405 U.S. 948 (1972) (*Florida Power & Light*).

[372] 404 U.S. at 456.

[373] *Id.* at 456.

[374] A ''bus'' is a connector or group of connectors that serves as a common connection for two or more circuits.

[375] 404 U.S. at 457.

[376] *Id.*

[377] *Id.* at 457 & n.8.

[378] *Id.* at 461. (emphasis omitted).

[379] *Id.* at 461 n.10. (emphasis added).

[380] *See* Section 201(d), 16 U.S.C. § 824(d) (1988).

[381] *Public Utilities Commission, supra* note 345; City of Oakland, *California* v. *FERC,* 754 F.2d 1378 (9th Cir. 1985) (*Oakland*). See also *Alexander* v. *FERC,* 609 F.2d 543 (D.C. Cir. 1979) (*Alexander*).

[382] Courts often rely on cases construing the NGA when interpreting the FPA, and vice versa. *E.g., Arkansas Louisiana Gas Co.* v. *Hall,* 453 U.S. 571, 577 n.7 (1981).

[383] 15 U.S.C. 717(b) (emphasis added).

[384] H.R. Rep. No. 709, 75th Cong., 1st Sess. 3 (1937); S. Rep. No. 1162, 75th Cong., 1st Sess. 3 (1937).

pipelines connected inside Ohio with East Ohio's large high pressure lines. The gas then was transported over 100 miles through East Ohio's system to its local distribution system. East Ohio argued that it was exempt from Commission jurisdiction because all of its facilities were local distribution.

The Court disagreed, finding the Commission's jurisdiction extends over the transportation of gas in interstate commerce through high-pressure transmission lines and that distribution did not begin until the point where pressure is reduced and gas enters local mains. The Court stated that: ''[w]hat Congress must have meant by 'facilities' for 'local distribution' was equipment for distributing gas among customers within a particular local community, not the high-pressure pipelines transporting the gas to the local mains.'' [385]

The Commission relied in part on *East Ohio's* high pressure/low pressure distinction in a recent NGA section 7 certificate case which authorized construction of facilities to bypass the local distribution company.[386] On appeal, the California Commission argued that under section 1(b) it should at least have ''jurisdiction over the 'taps, meters and other tie-in facilities' that link the pipeline to end users.'' [387] The court disagreed:

> While as a matter of ordinary English 'local distribution' might be understood to encompass any delivery to an end user, that is hardly the only or even more plausible reading. Distribution conjures up receiving a large quantity of some good and parcelling it out among many takers.[388]

After reviewing the report language discussed above, the court also stated:

> Insofar as congressional committees spoke to the matter * * * they appear to have viewed distribution as confined to its parcelling out function and (probably) even more narrowly, to parcelling out *accompanied by* retail sales.[389]

In *Cascade Natural Gas Corporation* v. *FERC, et al. (Cascade),* the court affirmed the Commission's authorizing an interstate pipeline under section 7 of the NGA ''to construct a tap and meter facility that would allow it to deliver natural gas directly to two industrial consumers * * *.'' [390] To reach the interstate pipeline, the industrials constructed a nine-mile pipeline. Together, the facilities bypassed the local distribution company.[391]

The court rejected arguments that section 1(b) deprived the Commission of jurisdiction holding that:

> ''Local distribution,'' as Congress viewed the term, involves two components: the retail sale of natural gas and its local delivery, normally through a network of branch lines designed to supply local consumers.[392]

5. Analysis

a. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user? The case law supports the conclusion that any facilities of a public utility used to deliver electric energy in interstate commerce to a wholesale purchaser, whether such facilities are labeled ''transmission,'' ''distribution'' or ''local distribution,'' are subject to the Commission's jurisdiction under sections 205 and 206.

This conclusion is supported by *Public Utilities Commission, supra,* in which the Supreme Court, in the section of its opinion addressing the section 201(b) local distribution provision, held that local distribution facilities began ''only after the current was subdivided for individual consumers.'' [393] *Wisconsin-Michigan, supra,* in which the Seventh Circuit held that there is no local distribution until the wholesaler who re-sells at retail is reached, is to like effect.

This conclusion, which results in a ''functional'' line being drawn to determine Commission jurisdiction, is not only consistent with the case law under section 201, but is also consistent with our interpretation of the line drawn under newly amended FPA sections 211 and 212. As long as electric energy is being sold to a legitimate wholesale purchaser, we believe the Commission has jurisdiction under sections 201, 205, and 206 of the FPA over the public utility's facilities used to deliver electric energy to that purchaser.

b. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier directly to an end user? In analyzing jurisdiction over unbundled retail wheeling, we believe it is important to distinguish between unbundled wheeling provided by the public utility who previously provided bundled retail service to the end user, and unbundled wheeling provided by other public utilities to the end user. For example, a former bundled retail customer may need unbundled wheeling services from its previous public utility generation supplier, as well as unbundled wheeling from one or more intervening public utilities, in order to reach a distant generation supplier. In this scenario, the Commission believes it would have jurisdiction over all of the facilities used for the unbundled wheeling provided by the intervening public utilities.[394] The more difficult issue is whether some portion of the facilities used to transmit energy from the transmitting utility in closest proximity to the end user (the former supplier of the bundled product) is local distribution facilities. We believe that in most, if not all circumstances, some portion will be local distribution facilities.

The case law is replete with statements that the local distribution provision of section 201 must be given effect. However, the Supreme Court in both *CL&P* and *Colton, supra,* has stated that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. Thus, there is no clear case law on a ''bright line'' between transmission and local distribution. In addition, regardless of the details of the chain of delivery services necessary to move electric energy from the generator to the end user, in most cases the last public utility in the chain will use facilities that historically were considered local distribution facilities. Accordingly, unlike the situation involving unbundled wholesale wheeling, for which the case law clearly supports a ''functional'' test, the Commission believes the case law and practical realities of a changing industry support an analysis of local distribution facilities based on the facilities' functional as well as technical characteristics.

While it would be preferable to draw an absolutely ''bright'' line (*e.g.*, based on technical characteristics such as voltage), this does not appear to be

[385] 338 U.S. at 469–70.

[386] See Mojave Pipeline Company, 35 FERC ¶ 61,199 (1986), *reh'g denied*, 41 FERC ¶ 61,040 (1987), *reh'g denied*, 42 FERC ¶ 61,351 (1988); *see also* Mojave Pipeline Company, 66 FERC ¶ 61,194 (1994), *reh'g pending*.

[387] See *Public Utilities Commission of the State of California* v. *FERC, et al.*, 900 F.2d 269, 273 (D.C. Cir. 1990) (footnote omitted) (*WyCal*).

[388] *Id*. at 276.

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

[390] 955 F.2d 1412, 1414 (10th Cir. 1992).

[391] Unlike the situation in *WyCal* where the pipeline made direct sales to end users, in *Cascade* the pipeline transported gas purchased from third parties. See Northwest Pipeline Corporation, 51 FERC ¶ 61,289 at 61,909 (1990).

[392] *Cascade*, 955 F.2d at 1421.

[393] 345 U.S. at 316 (footnote omitted).

[394] The Commission would not have jurisdiction over the rates for the sale of generation by the distant supplier because the transaction would be a retail sale of electric energy.

required by the case law and, importantly, would not be a workable approach in all cases because of the variety of circumstances that may arise and because utilities themselves classify facilities differently (*e.g.*, one utility may classify a 69 kV facility as transmission; another may classify it as distribution).

There are several indicators that we propose to evaluate in determining whether particular facilities are transmission or local distribution in the case of vertically integrated transmission and distribution utilities.[395]

- Local distribution facilities are normally in close proximity to retail customers.
- Local distribution facilities are primarily radial in character.
- Power flows into local distribution systems, it rarely, if ever, flows out.
- When power enters a local distribution system, it is not reconsigned or transported on to some other market.
- Power entering a local distribution system is consumed in a comparatively restricted geographical area.
- Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
- Local distribution systems will be of reduced voltage.[396]

In summary, for unbundled wholesale wheeling we will apply a functional test. The only definitive question will be whether the entity to whom the power is delivered is a lawful wholesaler.

For unbundled retail wheeling we will apply a combination functional-technical test that will take into account technical characteristics of the facilities used for the wheeling. In most, if not all, circumstances in this situation, we expect there to be local distribution facilities. To assist states in dealing with stranded costs resulting from retail wheeling, we will make every attempt to expedite a decision if a state requests clarification concerning whether certain facilities are local distribution facilities.

By clarifying the tests the Commission will apply to determine if facilities used to deliver unbundled electric energy are FERC-jurisdictional or state-jurisdictional, we believe we have facilitated the ability of this Commission and, importantly, state commissions to assess legitimate stranded costs to customers who leave their existing suppliers' systems. The application of these tests means that states will be able to address stranded costs by imposing an exit fee on departing retail customers, or including an adder in the retail customers' local distribution rates.

H. Implementation

Because the proposed requirements in the Open Access NOPR are aimed at eliminating undue discrimination in the provision of transmission services in interstate commerce, and at achieving competitive bulk power markets for the benefit of electricity consumers, our preliminary view is that open access tariffs should be in place as soon as possible. Very simply, we would not want to delay a program which we expect to produce significant ratepayer benefits over time. We also would want to provide procedures and guidance for stranded cost recovery as soon as possible in order to complete the transition from a tightly-controlled cost-of-service regulatory regime to the competitive regime we expect in the very near future.

To those ends, we propose implementation procedures that the Commission currently believes will be appropriate for non-discriminatory open access transmission and stranded (transition) cost recovery. These proposed implementation procedures attempt to balance the goals of: Placing good open access tariffs into effect as soon as possible; supporting the transmission pricing flexibility permitted by our Transmission Pricing Policy Statement; and providing for implementation that is administratively feasible for utilities, customers, and the Commission.

With respect to open access, we currently estimate that about 137 public utilities would be required to have on file non-discriminatory open access tariffs if the Commission adopts a final rule.

If the Commission were to employ traditional filing procedures in implementing an open access regime, we could attempt to streamline the process by, for example, relying, where appropriate, on paper hearing procedures and technical conferences and summarily disposing of the maximum number of issues possible. Nevertheless, we would still expect delays (and attendant uncertainty) measured in years.[397] As a result, we propose a two-stage procedure to put in place without delay basic open access tariffs. We believe this procedure will ensure non-discriminatory open access transmission services that would: (1) Satisfy most utilities and customers; and (2) provide a framework for utilities to subsequently submit novel proposals that they believe to be better tailored to their individual circumstances. We request comments on all aspects of the proposed procedure, including the proposed generic tariffs discussed *infra*.

1. Two-Stage Implementation Process

Stage One

The Commission proposes to put into effect (not subject to refund) for every public utility that owns and/or controls transmission facilities, pursuant to section 206 of the FPA, generic tariffs providing network transmission services, firm and non-firm point-to-point transmission services, and ancillary services necessary to effect network and point-to-point service.[398] The Commission proposes to specify the rates, terms, and conditions in the final rule and to put all such tariffs into effect simultaneously on a date certain—12:00 midnight 60 days after the effective date of the final rule.

The proposed network and point-to-point tariffs contained in Appendices B and C establish the minimum terms and conditions which we believe are necessary to eliminate undue discrimination in the transmission of electric energy in interstate commerce. We propose to place these terms and conditions into effect for each affected public utility.

Although the proposed generic tariffs contain the minimum terms and conditions of service that is not unduly discriminatory, they do not contain specific rates. However, section 206(a) of the FPA requires the Commission to fix by order the just and reasonable rate.[399] We therefore propose to establish and set forth in the final rule, for each affected public utility, just and reasonable rates for network service, point-to-point service, and six identified ancillary services. We propose to

[395] In the case of a distribution-only utility, which is franchised by a State or local government and sells only at retail, all of the circuits (and related wires, transformers, towers, and rights of way) which it owns or operates (regardless of voltage) would be local distribution facilities.

[396] The Commission has analyzed utilities' filings required by the Commission's regulations. These filings are made on FERC Form No. 1. While there is no uniform breakpoint between transmission and distribution, it appears that utilities account for facilities operated at greater than 30 kV as transmission and that distribution facilities are usually less than 40 kV.

[397] Such uncertainty could adversely impact on utilities' cost of capital. Moreover, case-by-case implementation would result in a patchwork of open access around the country until the process is complete. This patchwork of conflicting requirements could inhibit the timely transition to competitive markets—a result directly at odds with the objectives of this proceeding.

[398] As noted *infra*, we will address in a separate document the application of the proposed rule to public utilities who have open access proceedings pending before the Commission.

[399] *Electrical District No. 1, et al.* v. *FERC*, 774 F.2d 490 (D.C. Cir. 1985).

establish such rates using the most current Form No. 1 data available for each public utility, and to incorporate them into the generic tariffs for each affected public utility.

While the rates we will calculate using Form No. 1 data will be postage stamp rates, we wish to emphasize that utilities are free in Stage Two to propose immediately and support non-traditional conforming, as well as non-conforming, transmission pricing proposals consistent with the Commission's Transmission Pricing Policy Statement. The proposed calculation of these rates is discussed in detail *infra.*

Customers will be able to rely on existing contracts for transmission service until such contracts expire or are otherwise terminated. While customers will be able to use the generic tariffs and any revised tariffs established in Stage Two for new or additional services, we do not propose to allow customers to seek termination of their existing transmission arrangements in order to use the generic or subsequently revised tariffs, unless such filings are contractually authorized or shown to be in the public interest. Of course, to the extent that such filings are contractually authorized, the Commission must still determine whether the termination of such existing transmission arrangements is just and reasonable, based upon the circumstances presented.

The above procedures would apply to individual public utility open access tariffs. However, many public utilities transact under jurisdictional power pooling agreements. As discussed herein, power pools would have to comply with the non-discrimination requirements of the Open Access NOPR by making power pool transmission services available to all wholesale transmission customers and offering services at rates, terms, and conditions that are not unduly discriminatory. However, power pools raise complex issues and the Commission cannot at this time develop compliance tariffs for power pools. Therefore, we seek comments on how to implement the NOPR for power pools. After we have received comments on this matter, and before a final rule is adopted, we intend to hold technical conferences with power pools to discuss implementation issues. After holding these technical conferences, and taking into account the comments received in the Open Access NOPR proceeding as well as in our pending Notice of Inquiry on Alternative Power Pooling Institutions, we will issue a supplemental order directing compliance for power pools.

Stage Two

The Commission proposes that Stage Two begin 61 days after the date the final rule becomes effective. On and after that date, public utilities may propose changes to the rates, terms, and conditions in the generic tariffs pursuant to section 205 of the FPA and Part 35 of the regulations. In addition, customers and others may file complaints pursuant to section 206 of the FPA seeking changes in the rates, terms, and conditions in the generic tariffs. We note, however, that Stage Two tariffs must contain at least the non-price tariff terms and conditions contained in the *pro forma* tariffs. Moreover, customers (or potential customers) dissatisfied with the generic tariffs may file section 211 applications at any time (*i.e.,* before Stage Two).

We are hopeful that the generic tariffs will initially be acceptable to large numbers of utilities and their customers. Because we expect our Stage One tariffs to be satisfactory for the immediate needs of many transmission providers and customers, we would expect Stage Two proposals to be staggered somewhat, permitting us to process and reach final decisions more quickly on subsequent proposals to revise the generic tariffs.

We propose to require any utility seeking to modify the generic tariffs in Stage Two to file, in addition to the other requirements specified in the regulations, an original and 14 copies of the revised tariffs showing any changes proposed by means of highlighting and striking out. In addition, we propose that the utilities also file two copies of such changes on diskette in ASCII format.

2. Calculations of Stage One Rates

Because most utilities currently use embedded cost pricing for the transmission component of their own power sales and purchases, and because the Commission's Transmission Pricing Policy Statement requires comparability between transmission rates and the transmission pricing component of those power sales and purchases, the Commission proposes to establish rates for the generic tariffs based on embedded cost principles. However, these tariffs will include a provision that allows the transmission provider to file unilateral changes in all rates, terms, and conditions any time after the effective date of the generic tariffs (Stage Two filings). However, as we noted above, the minimally acceptable tariff terms and conditions in Stage Two will be the terms and conditions established in Stage One.

We emphasize that utilities and customers have discretion under the Commission's Transmission Pricing Policy Statement to pursue other types of rate treatments, and that they may file a proposal any time after the generic tariffs become effective. For example, Stage Two filings could include:

- A filing by the public utility under section 205 amending the generic tariff in a limited respect, such as a change in the loss factor, a change in the embedded cost unit charge, implementing an option to charge an incremental cost rate, including opportunity cost, when capacity is constrained, or the addition of another ancillary service.
- A filing by the public utility under section 205 proposing an entirely new rate method such as a zone or distance based transmission rate. The generic tariff would constitute a conforming open access transmission tariff, but revised tariff filings could also include nonconforming proposals.
- A complaint by a customer (or potential customer) under section 206 seeking limited changes to the generic tariff, such as a change in the loss factor, a change in the embedded cost unit charge, or the addition of another ancillary service.
- A complaint by a customer (or potential customer) under section 206 proposing an entirely new rate method.

We expect that, for many transmission providers and customers, the Stage One tariffs will satisfy their immediate needs. For example, a customer might believe that it could demonstrate in a section 206 proceeding that a lower rate is appropriate, but decide the monetary impact is not sufficient to justify the filing of a complaint because its current needs are small or because the expected rate reduction is slight. In this situation, the customer may delay raising objections to the Stage One tariffs until the company files its next general rate case. Also, a company might believe that it could demonstrate that a higher rate is reasonable, but decide that its resources are best spent comprehensively designing a Stage Two non-traditional tariff, such as, a distance sensitive rate, a non-conforming proposal, or a spin-off of transmission assets into a separate company. Similarly, companies negotiating regional transmission tariffs may decide to devote their resources to that project rather than fine tuning their company specific rates.

If we had not proposed this two-stage process and simply directed the filing of company specific tariffs, utilities and customers would have been forced to proceed on an inflexible schedule. In addition, parties may have felt pressured to file proposals prematurely out of concern that a failure to do so would prejudice their ability to initiate them later. We believe that industry participants are better served by a process that, in addition to avoiding the delay inherent in a series of separate section 206 compliance filings, allows affected parties to raise these complex issues when it best meets their needs and after taking whatever time is necessary to evaluate non-traditional alternatives.

The Commission proposes to establish the rates for Stage One tariffs as follows:

Derivation of the Embedded Cost Transmission Charge for Point-to-Point Service

To establish firm point-to-point transmission charges, the Commission proposes to use the fixed charge methodology that it uses to evaluate rate schedule filings. This methodology is available to the public on the Commission's Electric Power Data Bulletin Board and has been referenced in various proceedings before the Commission.[400]

Form No. 1 data are used to develop the cost relationship between fixed transmission costs and transmission plant investment (a fixed charge rate). The unit charge is calculated by: (1) Dividing plant investment by capability, using the annual system peak as a proxy for capability;[401] and (2) multiplying the result by the fixed charge rate. All data would be taken from the Form No. 1 except the return on equity.

For the equity return, the Commission proposes to use an industry-wide return calculated using the Commission's standard discounted cash flow (DCF) analysis of company specific dividend yields and an industry average constant growth rate.[402] As an alternative, the Commission could use its DCF method to compute company specific equity returns. However, this is not likely to change materially the Stage One rates (*e.g.*, a 1% change in the equity return would change the monthly charge by about $.08/kW/month, equivalent to an hourly charge of 0.1 mill/kWh). We invite comments on this issue.

We also propose an alternative rate treatment and we ask for comment on which we should adopt for all affected public utilities. The alternative is a variation of our fixed charge rate method. Under our alternative proposal, the Commission would multiply an industry-wide transmission fixed charge rate by the company-specific investment cost per kW from the Form No. 1.[403] This would simplify the process. In our experience, differences in unit charges among companies are due primarily to differences in investment cost per kW of capability and not the fixed charge rate. We note that we adopted a similar approach in developing cost-based ceiling rates for the WSPP, although we developed a single composite rate for WSPP services.

The following illustrates the computation of a specific Stage One point-to-point transmission charge for three utilities using the alternative proposal and 1993 Form No. 1 data, Dayton Power & Light Company (Dayton), Louisville Gas & Electric Company (LGE), and Minnesota Power & Light Company (MPL):

(1) Company	(2) Transmission plant in service (000)	(3) System peak MW	(4) Annual charge (2)/(3)×17.5%
(1) Dayton	$247,186	2,765	$15.64/kW
(2) LGE	173,836	2,239	13.59/kW
(3) MPL	162,656	1,252	22.74/kW

Under either alternative, the final rule would establish specific unit charges. Charges for shorter term services would be derived from the annual charge using standard Commission methods:

Monthly Charge = Annual Charge/12

Weekly Charge = Annual Charge/52

Daily Charge = Weekly Charge/5

Hourly Charge = Daily Charge/16

Revenues for daily and hourly service would be capped at the equivalent weekly and daily rates pursuant to our standard requirements.[404]

We propose to establish ceiling rates for non-firm service equal to the firm rates, consistent with industry practice. As a practical matter, there is generally a charge for non-firm service only in the hours when energy is scheduled and, therefore, non-firm service is provided at a discount from firm service, which is generally subject to a charge based on reservations without regard to actual usage. As we have emphasized in the past, we expect that a rate for firm service will be higher than a rate for another service that differs only in the degree of firmness.[405] We also expect that such discounts will be offered on a non-discriminatory basis to all customers and that customers will have sufficient information about the availability of discounts (*e.g.*, through an information network).

Derivation of Embedded Cost Charge for Network Service

To establish network transmission charges, the Commission proposes to adopt the load ratio method we approved in *Florida Municipal Power Agency*.[406] Under this approach, the company's annual transmission costs (the product of column (2) in the table above for point-to-point service and the same fixed charge rate used to develop the point-to-point rates) are multiplied by a load ratio percentage. The load ratio reflects the average of the 12 monthly customer coincident peaks divided by the average of the 12 monthly total system peaks. Total monthly system peaks for this calculation would reflect all firm uses of the transmission system, including the transmission owners' own long term

[400] See, *e.g.*, Western Systems Power Pool (*WSPP*), 55 FERC ¶ 61,099 (1991); Jersey Central Power & Light Company, 38 FERC ¶ 61,275 (1987); and UtiliCorp United Inc., 70 FERC ¶ 61,149 (1995).

[401] The Commission consistently requires this method for non-customer specific rates such as this. See, *e.g.*, American Electric Power Service Company, 67 FERC ¶ 61,168 (1994); Kentucky Utilities Company, 67 FERC ¶ 61,189 (1994).

[402] An industry-wide return on equity calculated using this method would currently yield a return of about 11%.

[403] Based on analyses prepared by the Commission's staff to support acceptance of filings tendered by utilities during the last two years, a representative transmission fixed charge rate is 17.5%. The Form No. 1 data used to compute a company specific investment cost per kW of load is found at Page 207, line 69, column g (end of year plant transmission plant in service) and Page 401, column D (system peak load) of the Form No. 1.

[404] See Appalachian Power Company, *et al.*, 39 FERC ¶ 61,296 at 61,965 (1987); *WSPP, supra*, 55 FERC at 61,321.

[405] Commonwealth Edison Company, 64 FERC ¶ 61,253 (1993).

[406] See *supra*, 67 FERC at 61,481.

firm and unit power sales. We shall specify the annual revenue requirement in the generic tariff and direct the transmission provider to insert the load ratio computation into the service agreement when filed after a request for service is accepted by the utility.

Derivation of the Charges for Ancillary Services

Loss Compensation

The Commission proposes to establish a loss factor of 3% and a charge for energy losses equal to 110% of seller's incremental cost. A 3% loss factor is representative of those in transmission agreements on file and a loss compensation charge based on the seller's incremental cost is also common.

Energy Imbalances

The Commission proposes to establish an hourly deviation band of +/- 1.5% with a minimum of 1 MW per hour and imbalances within this band would be returned in kind or subject to a charge equal to seller's incremental cost (or a payment equal to decremental cost if the public utility transmission provider receives too much energy and must compensate the transmission customer). Energy imbalances outside this band would be subject to a charge of 100 mills/kWh, the standard industry rate for emergency service. We propose the emergency service charge for this purpose because, as with emergency service, the rate should provide an incentive to minimize energy imbalances. We seek comment on the size of the deviation band and size of the imbalance charge.

Scheduling & Dispatching Charges

The Commission's fixed charge rate methodology which will be used to establish the transmission charge includes Account No. 566, where the costs of transmission related scheduling and dispatching are booked. Accordingly, the generic tariffs would include no separate charge for scheduling and dispatching. This should be adequate for most transmission services because most customers are likely to require this scheduling and dispatching service. If a customer does not require this service, it may propose a different rate treatment by filing a complaint at Stage Two.

Other Charges

The other ancillary services—Load Following, System Protection, and Reactive Power—have a common attribute. They all involve the cost incurred by the transmission provider as a result of using generation facilities to support the transmission service. In the past, some or all of these services were often provided at a rate reflecting embedded transmission costs, *i.e.*, without a separate charge reflecting the cost of generation facilities. However, the Commission has allowed a 1 mill/kWh charge for difficult to quantify costs that served to compensate transmission providers for costs like these. We propose, for purposes of the Stage One tariffs, to maintain a ceiling of 1 mill/kWh as the charge for these three ancillary services on a combined basis. We would expect that the parties would negotiate charges below this ceiling if the customer can provide some or all of these ancillary services and that this would be filed as a change in Stage Two. We emphasize that, if a utility believes that a 1 mill/kWh charge is unsatisfactory, it may file to revise the charge under section 205 in Stage Two. Similarly, if a customer finds a 1 mill/kWh charge unsatisfactory, it may file a complaint in Stage Two.

Questions

We invite comments on which of the methodologies we should adopt. For example, we are interested in commenters' preference for the first alternative, which uses company specific Form No. 1 data for all inputs, or the second alternative, which uses company specific Form No. 1 data only for investment and load. With respect to the first alternative, we seek comments on our proposal to use an industry-wide equity return for each affected public utility and, with respect to the second alternative, we seek comments on our proposed uniform 17.5% transmission fixed charge rate. We also seek comments as to whether a more specific definition of the load ratio should be adopted, and whether this ratio can be used fairly in all situations. We also invite comments on our proposals for ancillary service charges. All comments should take into account our intention to immediately put in place generic tariffs so that there will be no delay in the availability of nondiscriminatory open access transmission services.

3. Ongoing Proceedings

There are currently a number of ongoing proceedings in which the Commission is investigating utilities' open access tariff filings. Concurrently with this order, the Commission is issuing a separate order concerning those cases.

IV. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA)[407] requires that rulemakings contain either a description and analysis of the effect the proposed rule will have on small entities or a certification that the rule will not have a substantial economic effect on a substantial number of small entities. Because the entities that would be required to comply with the proposed rule are public utilities and transmitting utilities that do not fall within the RFA's definition of small entities,[408] the Commission certifies that this rule will not have a ''significant economic impact on a substantial number of small entities.''

V. Environmental Statement

The Commission concludes that promulgating the proposed rule would not represent a major federal action having a significant adverse impact on the human environment under the Commission's regulations implementing the National Environmental Policy Act.[409] The proposed rule falls within the categorical exemption provided in the Commission's regulations for electric rate filings submitted by public utilities under sections 205 and 206 of the FPA.[410] Consequently, neither an environmental assessment nor an environmental impact statement is required.

VI. Information Collection Statement

The Office of Management and Budget's (OMB) regulations[411] require that OMB approve certain information and recordkeeping requirements imposed by an agency.

The information collection requirements in the proposed regulations are contained in FERC–516, ''Electric Rate Filings'' (OMB approval No. 1902–0096). The Commission uses the data collected in this information collection to carry out its responsibilities under Part II of the FPA. The Commission's Office of Electric Power Regulation uses the data to review electric rate filings. The data enable the Commission to examine and evaluate the utility's costs and rate of return.

The Commission is submitting notification of this proposed rule to OMB. Interested persons may obtain

[407] 5 U.S.C. 601–612.

[408] 5 U.S.C. 601(3) (citing section 3 of the Small Business Act, 15 U.S.C. 632). Section 3 of the Small Business Act defines a ''small-business concern'' as a business which is independently owned and operated and which is not dominant in its field of operation. 15 U.S.C. 632(a).

[409] 18 CFR Part 380.

[410] 18 CFR 380.4(a)(15).

[411] 5 CFR 1320.13.

information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 941 North Capitol Street, NE., Washington, DC 20426 [Attention: Michael Miller, Information Services Division, (202) 208–1415]. Comments on the requirements of the proposed rule can also be sent to the Office of Information and Regulatory Affairs of OMB [Attention: Desk Officer for Federal Energy Regulatory Commission].

VII. Public Comment Procedures

The Commission invites comments on the proposed rule from interested persons. An original and 14 copies of written comments on the proposed rule must be filed with the Commission no later than August 7, 1995.

The Commission will also permit interested persons to submit reply comments in response to the initial comments filed in this proceeding. Reply comments should be submitted no later than October 4, 1995.

In addition, commenters are requested to submit a copy of their comments on a 3½ inch diskette formatted for MS–DOS based computers. In light of our ability to translate MS–DOS based materials, the text need only be submitted in the format and version that it was generated (*i.e.*, MS Word, WordPerfect, ASCII, etc.). It is not necessary to reformat word processor generated text to ASCII. For Macintosh users, it would be helpful to save the documents in Macintosh word processor format and then write them to files on a diskette formatted for MS–DOS machines. All comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, and should refer to Docket Nos. RM95–8–000 and RM94–7–001.

All written comments will be placed in the Commission's public files and will be available for inspection in the Commission's public reference room at 941 North Capitol Street, NE., Washington, DC, 20426, during regular business hours.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission.

Commissioner Massey concurred in part and dissented in part with a separate statement attached.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission proposes to amend part 35, chapter I, title 18 of the Code of Federal Regulations, as set forth below.

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Part 35 is amended by revising § 35.15, by redesignating § 35.28 as § 35.29, and by adding new §§ 35.26, 35.27, and 35.28 to read as follows:

§ 35.15 Notices of cancellation or termination.

(a) General rule

When a rate schedule or part thereof required to be on file with the Commission is proposed to be cancelled or is to terminate by its own terms and no new rate schedule or part thereof is to be filed in its place, each party required to file the schedule shall notify the Commission of the proposed cancellation or termination on the form indicated in § 131.53 of this chapter at least sixty days but not more than one hundred-twenty days prior to the date such cancellation or termination is proposed to take effect. A copy of such notice to the Commission shall be duly posted. With such notice each filing party shall submit a statement giving the reasons for the proposed cancellation or termination, and a list of the affected purchasers to whom the notice has been mailed. For good cause shown, the Commission may by order provide that the notice of cancellation or termination shall be effective as of a date prior to the date of filing or prior to the date the filing would become effective in accordance with these rules.

(b) Applicability

(1) The provisions of paragraph (a) of this section shall apply to all contracts for unbundled transmission service and all power sale contracts:

(i) Executed prior to [INSERT DATE 90 DAYS AFTER THE FINAL RULE IS PUBLISHED IN THE **FEDERAL REGISTER**]; or

(ii) If unexecuted, filed with the Commission prior to [INSERT DATE 90 DAYS AFTER THE FINAL RULE IS PUBLISHED IN THE **FEDERAL REGISTER**].

(2) Any power sales contract executed on or after [INSERT DATE 90 DAYS AFTER THE FINAL RULE IS PUBLISHED IN THE **FEDERAL REGISTER**] shall not be subject to the provisions of paragraph (a) of this section.

(c) Notice

Any public utility providing jurisdictional services under a power sales contract that is not subject to the provisions of paragraph (a) of this section shall notify the Commission of the date of the cancellation or termination of such contract within 30 days after such cancellation or termination takes place.

§ 35.26 Recovery of stranded costs by public utilities and transmitting utilities.

(a) Purpose

This section establishes the standards that a public utility or transmitting utility must satisfy in order to recover stranded costs.

(b) Definitions

(1) *Wholesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) A retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

(2) *Wholesale requirements customer* means a customer for whom a public utility or transmitting utility provides by contract any portion of its bundled wholesale power requirements.

(3) *Wholesale transmission services* has the same meaning as provided in section 3(24) of the Federal Power Act: the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.

(4) *Wholesale requirements contract* means a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements.

(5) *Retail stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or transmitting utility to provide service to a retail customer that subsequently becomes, in whole or in part, an unbundled retail transmission services customer of that public utility or transmitting utility.

(6) *Retail transmission services* means the transmission of electric energy sold, or to be sold, in interstate commerce directly to a retail customer.

(7) *New contract* means any contract executed after July 11, 1994, or

extended or renegotiated to be effective after July 11, 1994.

(8) *Existing contract* means any contract executed on or before July 11, 1994.

(c) Recovery of Wholesale Stranded Costs

(1) *General requirement.* A public utility or transmitting utility will be allowed to seek recovery of wholesale stranded costs only as follows:

(i) No public utility or transmitting utility may seek recovery of wholesale stranded costs if such recovery is explicitly prohibited by a contract or settlement agreement, or by any power sales or transmission rate schedule or tariff.

(ii) If wholesale stranded costs are associated with a new wholesale requirements contract containing an exit fee or other explicit stranded cost provision, and the seller under the contract is a public utility, the public utility may seek recovery of such costs, in accordance with the contract, through rates for electric energy under sections 205 through 206 of the FPA. The public utility may not seek recovery of such costs through any transmission rate for section 205 or 211 transmission services.

(iii) If wholesale stranded costs are associated with a new wholesale requirements contract, and the seller under the contract is a transmitting utility but not also a public utility, the transmitting utility may not seek an order from the Commission allowing recovery of such costs.

(iv) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the public utility may seek recovery of stranded costs only as follows:

(A) If either party to the existing contract seeks a stranded cost amendment pursuant to a section 205 or section 206 filing made prior to the expiration of the contract, and the Commission accepts or approves an amendment permitting recovery of stranded costs, the public utility may seek recovery of such costs through section 205 rates for electric energy.

(B) If the existing contract is not amended to permit recovery of stranded costs as described in paragraph (c)(1)(iv)(A) of this section, the public utility may file a proposal, prior to the expiration of the contract, to recover stranded costs through section 205 or section 211 through 212 rates for wholesale transmission services to the customer.

(v) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a transmitting utility but not also a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the transmitting utility may seek recovery of stranded costs through section 211 through 212 transmission rates.

(vi) If a retail customer becomes a legitimate wholesale transmission customer of a public utility or transmitting utility, *e.g.*, through municipalization, and costs are stranded as a result of the retail-turned-wholesale customer's access to wholesale transmission, the utility may seek recovery of such costs through section 205 or section 211 through 212 rates for wholesale transmission services to that customer.

(2) *Evidentiary Demonstration for Wholesale Stranded Cost Recovery.* A public utility or transmitting utility seeking to recover wholesale stranded costs in accordance with paragraphs (c)(1)(iv) through (vi) of this section must demonstrate that:

(i) it incurred stranded costs on behalf of its wholesale requirements customer or retail customer based on a reasonable expectation that the utility would continue to serve the customer;

(ii) the stranded costs are not more than the customer would have contributed to the utility had the customer remained a wholesale requirements customer of the utility, or, in the case of a retail-turned-wholesale customer, had the customer remained a retail customer of utility; and

(iii) it has taken and will take reasonable measures to mitigate stranded costs.

(3) *Rebuttable Presumption.* If a public utility or transmitting utility seeks recovery of wholesale stranded costs associated with an existing contract, as permitted in paragraph (c)(1) of this section, and the existing contract contains a notice provision, there will be a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision.

(d) Recovery of Retail Stranded Costs

(1) *General requirement.* A public utility may seek to recover retail stranded costs through rates for retail transmission services only if the state regulatory authority does not have authority under state law to address stranded costs at the time the retail wheeling is required.

(2) *Evidentiary Demonstration Necessary for Retail Stranded Cost Recovery.* A public utility seeking to recover retail stranded costs in accordance with paragraph (d)(1) of this section must demonstrate that:

(i) it incurred stranded costs on behalf of a retail customer that obtains retail wheeling based on a reasonable expectation that the utility would continue to serve the customer;

(ii) the stranded costs are not more than the customer would have contributed to the utility had the customer remained a retail customer of the utility; and

(iii) it has taken and will take reasonable measures to mitigate stranded costs.

§ 35.27 Power sales at market-based rates.

Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity first placed in service on or after [INSERT DATE 30 DAYS AFTER THE FINAL RULE IS PUBLISHED IN THE **FEDERAL REGISTER**].

§ 35.28 Non-discriminatory open access transmission tariffs.

(a) Every public utility owning and/or controlling facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission no later than [INSERT DATE 90 DAYS AFTER THE FINAL RULE IS PUBLISHED IN THE **FEDERAL REGISTER**] tariffs of generally applicability for transmission services, including ancillary services, over these facilities on both a point-to-point basis and network basis consistent with the requirements of Order No. ______ (Final Order on Open Access and Stranded Costs).

(b) Every public utility owning and/or controlling facilities used for the transmission of electric energy in interstate commerce, but not in existence on [INSERT DATE THE FINAL RULE IS PUBLISHED IN THE **FEDERAL REGISTER**], must file tariffs of generally applicability for transmission services, including ancillary services, over these facilities on both a point-to-point basis and network basis consistent with the requirements of Order No. ______ (Final Rule on Open Access and Stranded Costs) no later than the date any agreement under which such public utility would engage in a sale of electric energy at wholesale in interstate commerce or the transmission of electric energy in interstate commerce is accepted for filing by the Commission.

(c) Any public utility that owns and/or controls facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, must take transmission service for such sales and/or purchases under the tariffs filed pursuant to paragraph (a) or (b) of this section.

Note: Appendix D and Commissioner Massey's statement will not appear in the *Code of Federal Regulations.*

Appendix D—Docket No. RM94–7–000, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities List of Commenters

1. Ad Hoc Coalition on Environmental and Consumer Protection (Ad Hoc Coalition), consisting of Environmental Action Foundation, Citizen Action, Consumer Federation of America, Greenpeace, Toward Utility Rate Normalization, Public Citizen, Sierra Club, Nuclear Information & Resource Service, Economic Opportunity Research Institute, and U.S. Public Interest Research Group
2. Alabama Public Service Commission
3. Allegheny Electric Cooperative, Inc.
4. Allegheny Power Service Corporation (Allegheny Power)
5. American Forest & Paper Association (American Forest)
6. American Public Power Association (APPA)
7. American Society of Utility Investors
8. Arizona Public Service Company
9. Arkansas Public Service Commission
10. Atlantic City Electric Company
11. Blue Ridge Power Agency, Northeast Texas Electric Cooperative, Sam Rayburn G&T Electric Cooperative and Tex-La Electric Cooperative (Blue Ridge)
12. California Public Utilities Commission
13. Centerior Energy Corporation
14. Central Maine Power Company
15. Central Vermont Public Service Corporation
16. Cities of Anaheim, Azusa, Banning, Colton and Riverside, California
17. City of Las Cruces, New Mexico
18. Coalition For Economic Competition, consisting of Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, and Rochester Gas & Electric Company
19. Coalition of California Utility Employees
20. Colorado Association of Municipal Utilities
21. Colorado Office of Consumer Counsel
22. Colorado Public Utilities Commission
23. Commonwealth Edison Company (Commonwealth Edison)
24. Competitive Electric Market Working Group (Competitive Working Group), consisting of Electric Clearinghouse, Inc., Enron Power Marketing, Inc., and Destec Power Services, Inc.
25. Conservation Law Foundation
26. Consumer-Owned Utilities in Maine, consisting of Eastern Maine Electric Cooperative, Inc., Fox Islands Electric Cooperative, Inc., Houlton Water Company, Isle au Haut Electric Power Co., Kennebunk Light & Power District, Madison Electric Works, Swans Island Electric Cooperative, Inc., Union River Electric Cooperative, Inc., and Van Buren Light & Power District
27. Consumers Power Company
28. Dairyland Power Cooperative
29. Department of Water and Power of the City of Los Angeles
30. Detroit Edison Company (Detroit Edison)
31. Direct Action For Rights and Equality
32. District of Columbia Public Service Commission
33. Duke Power Company
34. Duquesne Light Company
35. Edison Electric Institute (EEI)
36. Electric Consumers' Alliance
37. Electric Generation Association
38. Electricity Consumers Resource Council, the American Iron and Steel Institute and the Chemical Manufacturers Association (Industrial Consumers)
39. El Paso Electric Company
40. Enron Power Marketing, Inc. (Enron)
41. Entergy Services, Inc. (Entergy)
42. Environmental Action Foundation (Environmental Action)
43. Environmental Law and Policy Center of the Midwest
44. Florida Municipal Power Agency, Michigan Municipal Cooperative Group and Wolverine Power Supply Cooperative (Florida and Michigan Municipals)
45. Florida Power Corporation
46. Florida Public Service Commission (Florida Commission)
47. Fuel Managers Association
48. Houston Lighting & Power Company (Houston Lighting & Power)
49. Idaho Public Utilities Commission
50. Illinois Commerce Commission (Illinois Commission)
51. Illinois Power Company
52. Indiana Office of Utility Consumer Counselor
53. Indiana Utility Regulatory Commission (Indiana Commission)
54. Iowa Utilities Board
55. Irrigation and Electrical Districts' Association of Arizona
56. Land and Water Fund of the Rockies
57. Large Public Power Council
58. Long Island Lighting Company (Long Island Lighting)
59. Louisiana Energy and Power Authority
60. Maryland Public Service Commission
61. Massachusetts Department of Public Utilities
62. Metropolitan Edison Company, Pennsylvania Electric Company and Jersey Central Power & Light Company
63. Michigan Public Service Commission Staff
64. Mid-Atlantic Energy Project
65. Municipal Resale Service Customers of Ohio Power Company
66. National Association of Regulatory Utility Commissioners (NARUC)
67. National Association of State Utility Consumer Advocates (NASUCA)
68. National Black Caucus of State Legislators
69. National Independent Energy Producers (NIEP)
70. National Rural Electric Cooperative Association
71. New England Power Company
72. New York Mercantile Exchange
73. New York State Electric & Gas Corporation
74. New York State Public Service Commission (New York Commission)
75. North Carolina Electric Membership Corporation
76. North Dakota Public Service Commission
77. Northern States Power Company
78. Nuclear Energy Institute
79. Oglethorpe Power Corporation
80. Ohio Office of the Consumers' Counsel
81. Ohio Public Utilities Commission (Ohio Commission)
82. Older Women's League
83. Omaha Public Power District
84. Pace Energy Project
85. Pacific Gas and Electric Company
86. Pacific Gas and Electric Company and Natural Resources Defense Council
87. PECO Energy Company
88. Pennsylvania and Massachusetts Municipals
89. Pennsylvania Power & Light Company
90. Pennsylvania Public Utility Commission (Pennsylvania Commission)
91. Public Power Council
92. Public Service Company of New Mexico
93. Public Service Electric and Gas Company (Public Service Electric)
94. Rhode Island Division of Public Utilities and Carriers and Jeffrey B. Pine, Attorney General of the State of Rhode Island
95. Rural Utilities Service
96. Sacramento Municipal Utility District
97. San Diego Gas & Electric Company
98. Sierra Pacific Power Company
99. South Carolina Electric & Gas Company
100. Southern California Edison Company
101. Southern Company Services, Inc.
102. Stranded Cost Order Opponent Parties, consisting of the Delaware Municipal Electric Corporation, Village of Freeport, New York, City of Jamestown, New York, Town of Massena, New York, Modesto Irrigation District, M–S–R Public Power Agency, City of Santa Clara, California, and Southern Maryland Electric Cooperative, Inc. (SCOOP)
103. Suffolk County Electrical Agency
104. Sunflower Electric Power Corporation (Sunflower)
105. Tampa Electric Company
106. Tennessee Valley Authority (TVA)
107. Public Utility Commission of Texas (Texas Commission)
108. Texas Utilities Electric Company
109. Transmission Access Policy Study Group (TAPS)

110. TDU Customers, consisting of Chicopee Municipal Lighting Plant of the City of Chicopee, Massachusetts, Golden Spread Electric Cooperative, Inc., Holy Cross Electric Association, Inc., Kansas Electric Power Cooperative, Inc., Old Dominion Electric Cooperative, Seminole Electric Cooperative, Inc., South Hadley Electric Light Department of the Town of South Hadley, Massachusetts, and Westfield Gas and Electric Department of the City of Westfield, Massachusetts
111. Trigen Energy Corporation
112. United Illuminating Company
113. United States Department of Defense
114. United States Department of Energy (DOE)
115. United Utility Shareholders Association of America
116. Utility Investors and Analysts
117. Utility Working Group (consisting of Dominion Resources, Inc., Duke Power Company, Duquesne Light Company, Entergy Corporation, General Public Utilities Corporation, Niagara Mohawk Power Corporation, Northern States Power Company, Pacific Gas and Electric Company, Portland General Electric Company, Public Service Electric and Gas Company, San Diego Gas & Electric Company, Southern California Edison Company, and Wisconsin Electric Power Company)
118. Vermont Department of Public Service (Vermont Department)
119. Virginia Electric and Power Company
120. Virginia State Corporation Commission
121. Washington Utilities and Transportation Commission
122. Washington Water Power Company
123. Wheeled Electric Power Company
124. Wisconsin Electric Power Company
125. Wisconsin Power & Light Company (Wisconsin Power)
126. Wisconsin Public Service Commission
127. Wisconsin Wholesale Customers
128. Wyoming Public Service Commission

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities

Docket No. RM95–8–000

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

Docket No. RM94–7–001

Issued March 29, 1995.

Massey, Commissioner, *concurring in part and dissenting in part:*

I. Concurring Opinion

Today, the Commission takes the logical next step—a bold, aggressive and historic step—toward full and robust competition in the electric power industry. Our proposal will change fundamentally the nature of this industry, and the relationships among transmission-owning utilities, their customers and competing power suppliers.

Why now? An uninformed observer might think it somewhat startling, at the very least counterintuitive, that in the current political climate, at the very same time Congress is debating a regulatory moratorium, this Commission issues the most profound regulatory proposal for the electric utility industry since the New Deal legislation. Why now?

There are several compelling reasons. First, *now* is always the best time to end undue discrimination. Federal law ''bristles'' with concern about undue discrimination. The Federal Power Act does not allow this Commission to tolerate it. There will never be a better time than now to stop it.

Second, now is also an appropriate time to eliminate the industry's uncertainty over our policy directions. Uncertainty is deeply unsettling for this industry. Instead of focusing on how to beat the competition, industry participants must first speculate about the future rules of the competition. This is intolerable in the long term and, in the short-term, stifles creativity, initiative and investment. We believe industry participants will applaud efforts to end the uncertainty now.

Third, this Commission wants to move boldly toward customer choice and light-handed regulation of wholesale generation. We believe it will bring lower rates. But we are limited greatly by transmission market power. We cannot move forcefully in these directions if transmission owners are able to skew the market and eliminate competition by denying or delaying transmission access, or by offering inferior terms and conditions for transmission service. The current patchwork of transmission access impedes competition. We must move beyond voluntary open access tariffs and time-consuming and expensive case-by-case rulings on wheeling requests. Now is the time to eliminate the transmission market power of the utilities over which we have jurisdiction. How can there be truly robust competition if buyers and sellers can't reach each other? Those who believe in competition and lower rates will applaud this step.

And, fourth, we cannot move to new rules without assuring utilities that they will recover the costs they prudently incurred under the old rules. That is a fundamental principle of our NOPR. We must strive to eliminate the uncertainty in the industry over the way in which this Commission will address stranded cost issues. Now is the time to speak clearly on this critical issue.

For these reasons, now is not only an appropriate time, but may indeed be the best time to take this bold step toward truly robust competition. It is my fervent hope that the market-based solutions this proposal portends, and the giant step it takes toward eliminating industry uncertainty over policy directions and stranded cost recovery, will strike a responsive chord among lawmakers, other policy makers, and others who care about the future of this important industry.

I strongly support virtually all of this NOPR. The NOPR addresses dozens of open access and stranded cost issues in ways that have my wholehearted support.

For example, I agree strongly with the proposed requirements of open access tariffs. It is one thing to state somewhat blithely that we favor the golden rule of transmission access. That is about all we have said so far. It is another thing entirely, and much more valuable to industry participants, to put real meat on the bones of comparability. The extensive text of the order accomplishes this objective, with unparalleled clarity. In fact, this entire document is a persuasive, compelling, technically brilliant work.

Let me highlight three specific issues. First is the issue of the NOPR's effect on regional transmission groups. Some in the industry may erroneously conclude that this rulemaking will lessen the value of, and need for, RTGs. The order emphatically disagrees. As the order states:

RTGs are structures to reflect the interest of all of the grid's users, not just some. RTGs allow for consensual solutions to local or regional issues, instead of solutions imposed by FERC. RTGs can function as regional laboratories for experimentation on transmission issues. And, RTGs will provide a regional forum, a necessary predicate to regional cooperation.

In short, RTGs remain a key part of our vision of the future of this industry.

Second, the NOPR requires the new tariffs to include a reciprocity provision. This provision would ensure that a public utility offering transmission access to others can obtain similar service from its transmission customers. If customers want access on a public utility's transmission wires, they must be willing to offer access for the utility on their own transmission wires. That is only fair.

Third, the NOPR would require functional unbundling of public utilities' jurisdictional services. That is, utilities would be required to take transmission service (including ancillary services) for new wholesale sales and purchases of electric energy under the open access tariffs. The tariffs also must state separately the rates for each type of transmission or ancillary service. This requirement of functional unbundling will give public utilities the incentive to offer service on fair terms and conditions, since the public utility will have to live with the same terms and conditions it proposes for others.

Now let me turn to an issue involving symmetry of rights between customers and utilities. Today's order makes an explicit generic finding that it is in the public interest to allow utilities to make filings at FERC for the recovery of stranded costs even if their contracts contain so-called *Mobile-Sierra* restrictions that would bar such filings.[1] I fully agree with this conclusion. I believe the policy rationale justifying the recovery of stranded costs is so strong that the public interest test is met and such a generic finding is necessary.

I have some concern, however, about the fact that today's order does not sufficiently explore making that same type of public interest finding on behalf of customers. The order spends many pages making a persuasive case that the current environment, in which no more than a handful of utilities have filed open access tariffs, is rife with undue discrimination and can no longer be tolerated. This is the fundamental philosophical and legal underpinning for the order's new open access requirements.

[1] *United Gas Pipeline Co.* v. *Mobile Gas Service Corp., 350 U.S. 332 (1956); FPC* v. *Sierra Pacific Power Co.,* 350 U.S. 348 (1956).

But if the order's perception of undue discrimination is accurate, and I believe it is, would it not suggest that some power supply contracts negotiated in that environment were infected with undue discrimination and therefore unlawful? Would it not be appropriate, and more symmetrical, to allow such customers the right to make a filing asking the Commission to determine whether their current contract is unduly discriminatory, unjust or unreasonable? We would not, of course, allow such customers to escape their stranded cost responsibility in any event. Even if we allowed customers to make such filings, they would remain fully responsible for the costs reasonably incurred on their behalf.

A more symmetrical approach to customers and utilities during the transition to competitive markets would be consistent with the Commission's Order 636. There, the Commission granted all pipeline ''sales'' customers the right to choose other gas suppliers but granted all pipelines 100 percent recovery of their eligible and prudent transition costs. In granting ''conversion rights'' to pipeline sales customers, the Commission found that continued enforcement of customers' existing purchase obligations, entered into when pipelines provided bundled service and had a virtual monopoly over certain aspects of interstate service, was contrary to the requirements of the Natural Gas Act.

I am not suggesting today that we mirror precisely the natural gas model by granting all customers, regardless of contracts, the right to choose other suppliers. I am suggesting, however, that during the comment period we give full and fair consideration to the argument that power customers with contracts lacking explicit stranded cost recovery provisions should have the same right we grant utilities to make filings seeking contract modifications regardless of *Mobile-Sierra* restrictions. I am confident that commenters will give us the benefit of their thinking on this issue.

II. Dissenting Opinion

Finally, let me turn briefly to the sole issue on which I will be dissenting in part from an otherwise exceptionally strong order. That issue involves this Commission's role and relationship with the states in making determinations with respect to stranded costs arising from retail competition and from municipalizations.

There have been full and vigorous discussions at the Commission about how to handle this issue. My goal, which the entire Commission shares, is to strike an appropriate balance that ensures the recovery of stranded costs, and ensures that the legitimate rights of states are respected. We have all struggled with these issues in good faith. I simply disagree with the majority in certain respects about how to accomplish these goals.

First, I will address retail competition. Under the NOPR, this Commission would allow filings seeking recovery of stranded costs related to retail competition only when the state regulatory commission does not have authority under state law to address stranded costs at the time retail wheeling is required.

I find this approach too narrow. I would allow such filings when the state commission lacks authority to decide the issue or when the state commission has authority but does not decide the issue. I would not second-guess the state decision, but I would not allow retail stranded costs to ''fall through the cracks'' merely because the state commission has, but does not use, authority to decide the issue.

On municipalization, the NOPR proposes making this Commission the primary forum for seeking recovery of stranded costs. The NOPR says that, if a state has allowed recovery of any stranded costs from municipalized customers, this Commission will deduct that amount from the amount we determine to be recoverable. In other words, even when states have and exercise the authority to decide the recoverability of stranded costs related to municipalization, this Commission would take over and federalize the issue.

I cannot support this approach. The Federal Power Act does not constitute this Commission as the court of appeals to challenge unsatisfactory state decisions. It is not this Commission's role to stand in judgment of policy choices and decisions lawfully made by our state counterparts.

In my judgment, the following principles should govern this Commission's approach to stranded costs arising from either retail competition or municipalization. In either case, utilities are entitled to a decision on the recoverability of such costs. It would be unfair, and would unduly jeopardize the financial health of utilities, for stranded costs to slip through because no regulatory commission provides a forum and decides the issue.

For either retail competition or municipalization, when the state commission has authority to address the issue, and uses such authority to decide the recoverability of the stranded costs, the state's decision should not be second-guessed by this Commission. However, when a state commission does not have the authority to decide the recoverability of stranded costs, or has authority but does not use it, this Commission should act on requests for stranded cost recovery.

My approach would assure utilities of getting a decision on the merits of their claim. Costs would not be stranded for lack of a regulatory decision. At the same time, this Commission would allow states to make decisions, when they have authority, on issues of critical concern to their local utilities and ratepayers. Only if states lack, or fail to use, such authority would this Commission step in to assure the utility of receiving a decision on the merits.

My views on how we should handle stranded costs arising from municipalization are influenced by the fact that, according to commenters, roughly 14 states have municipalization statutes that do in fact authorize states to deal with stranded cost issues. Arkansas, for example, has a statute enacted in 1987 that appears to give the Arkansas Public Service Commission full authority to deal with the stranded cost issue in a way that protects both the remaining customers and shareholders. It is an extensive, thoughtful statute that deals with a wide range of issues. It is, apparently, the will of the sovereign state of Arkansas that this state statute be enforced. I see no reason to yank this issue from the Arkansas Commission, or from any other state commission that has statutory authority to act.

In that vein, if this Commission were to decide the recoverability of stranded costs for either retail competition or muncipalization (because the state lacked authority or did not decide the issue), I believe we should adopt procedures allowing the affected state commissions to participate in our proceeding in a meaningful way. Specifically, I propose allowing state participation through one of the procedures specified in section 209 of the Federal Power Act.[2] These include joint state boards, joint hearings, concurrent hearings and technical conferences. I have no views at this time on which of these tools could or should be used in particular cases. The decision on which of these tools to use can be made in individual cases, as they arise. But, clearly, they are useful mechanisms for obtaining state input in proceedings involving retail competition and municipalization.

For all of these reasons, I will concur in part and dissent in part. In virtually all respects, this is an excellent order; except as I have noted, it has my wholehearted support.

William L. Massey,

Commissioner.

[FR Doc. 95–8534 Filed 4–6–95; 8:45 am]

BILLING CODE 6717–01–P

---

18 CFR Parts 141 and 388

[Docket No. RM95–9–000]

Real-Time Information Networks; Notice of Technical Conference and Request for Comments

March 29, 1995

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Technical Conference and request for comments.

SUMMARY: The Federal Energy Regulatory Commission (Commission), is issuing this notice to announce a technical conference to be scheduled at a later date, and, in preparation for that conference, to request comments on: whether real-time information networks (RINs) or some other option is the best method to ensure that potential purchasers of transmission services receive access to information to enable them to obtain open access transmission service on a non-discriminatory basis from public utilities that own and/or control facilities used for the transmission of electric energy in interstate commerce; and what

[2] 16 U.S.C. 824h (1988).