

Report of the Committee on Regulations—Parts II and III, Federal Power Act

During 1986 and 1987, the Federal Energy Regulatory Commission (FERC or Commission) and the courts decided a number of significant cases under Parts II and III of the Federal Power Act. These include cases relating to (1) FERC jurisdiction over wholesale rates, (2) filings by non-traditional utilities, (3) market-based pricing, (4) the *Mobile-Sierra*¹ doctrine, (5) cost of service and rate design issues including prudence, cancelled plant, fuel charges, taxes, construction work in progress, the “end result” test, rate of return and antitrust, and (6) transmission.

I. FERC JURISDICTION OVER WHOLESALE TRANSACTIONS

The decision of the United States Supreme Court in *Nantahala Power & Light Co. v. Thornburg*² makes clear that a decision by the FERC allocating cost responsibility through resale contracts constituted a preemption of the issue which must be followed by state agencies in retail ratemaking. The decision accepted the *Narragansett*³ doctrine which applied to federal-state relationships in the filed rate doctrine announced in *Montana-Dakota Utilities Co. v. Northwestern Public Service Co.*⁴

The case involved two wholly-owned subsidiaries of the Aluminum Company of America: Nantahala Power & Light Co., which serves retail and wholesale customers in North Carolina; and Tapoco, Inc., which serves only the Alcoa industrial load in Tennessee. Nantahala and Tapoco each own hydroelectric facilities which were operated by the Tennessee Valley Authority (TVA) as part of a combined system, with energy provided jointly to Nantahala and Tapoco. An apportionment agreement between Nantahala and Alcoa divided that energy between them, and both Nantahala and Alcoa purchased power from TVA to supplement the energy from the Nantahala and Tapoco generation. The North Carolina Utilities Commission (NCUC) had treated Nantahala and Tapoco on a rolled-in basis for ratemaking purposes; the FERC, on the other hand, had refused to order roll-in, but set Nantahala's wholesale rates as if Nantahala had received more energy from the Nantahala and Tapoco hydroelectric facilities than was provided under the apportionment agreement.⁵

In overturning a decision of the North Carolina Supreme Court which

1. *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956).

2. *Nantahala Power & Light Co. v. Thornburg*, 106 S. Ct. 2349 (1986).

3. *Narragansett Elec. Co. v. Burke*, 119 R.I. 559, 381 A.2d 1358 (1977), *cert. denied*, 435 U.S. 972 (1978).

4. *Montana-Dakota Utils. Co. v. Northwestern Pub. Serv. Co.*, 342 U.S. 246, 251-52 (1951).

5. *Nantahala Power and Light Co.*, 19 F.E.R.C. ¶ 61,152, *reh'g denied*, 20 F.E.R.C. ¶ 61,430 (1982); 21 F.E.R.C. ¶ 61,222 (1982), *aff'd*, *Nantahala Power and Light Co. v. FERC*, 727 F.2d 1342 (4th Cir. 1984).

had affirmed the retail roll-in treatment,⁶ the U.S. Supreme Court held that the NCUC was preempted because (a) in setting just and reasonable rates for Nantahala's wholesale customers, the FERC had decided what constitutes a reasonable split of bulk power entitlements between Nantahala and Tapoco (even though it did not then modify the intercorporate bulk power agreements), and (b) the NCUC treated Nantahala as though it was able to obtain more entitlements than it was able to obtain under the FERC-filed contracts, thus "trapping" some of Nantahala's costs. The U.S. Supreme Court appeared to hold that the NCUC could adopt the same approach to Nantahala's retail rates as the FERC had with respect to wholesale rates.⁷

The U.S. Supreme Court left open the question of state jurisdiction over determining the prudence of purchasing power from a particular bulk power resource, as distinguished from the price of power. The Court stated: "Without deciding this issue, we may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably excessive if lower-cost power is available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price*."⁸ That kind of prudence inquiry has been upheld by state courts in *Sinclair Machine Products, Inc.*⁹ and *Pike County Light & Power Co. v. Pennsylvania Public Utility Commission*.¹⁰

The *Nantahala* decision has been followed in a number of cases in which the FERC or courts have found exclusive or primary FERC jurisdiction. Two significant series of cases are the Middle South Utilities System Grand Gulf cases and the AEP-Kentucky Public Service Commission disputes concerning cost responsibility for the Rockport units.

In *Mississippi Industries v. FERC*,¹¹ the U.S. Court of Appeals for the D.C. Circuit affirmed the FERC's authority, exercised in Opinion Nos. 234¹² and 234-A,¹³ over reallocation of electric generating plant cost responsibility among affiliates of Middle South Utilities (MSU). The court in *Mississippi Industries I* affirmed the allocation made but, on rehearing in *Mississippi Industries II*,¹⁴ adopted the dissenting opinion in *Mississippi Industries I* and found that the Commission had not adequately explained why the allocation method adopted was not unduly discriminatory. On remand in its Opinion No. 292,¹⁵ the FERC adhered to its allocation method and set forth in more

6. State ex. rel. Utils. Comm'n v. Nantahala Power & Light Co., 313 N.C. 614, 332 S.E.2d 397 (1985).

7. In an Order on Remand issued November 13, 1987, the NCUC adopted the FERC approach for the Nantahala retail rates at issue.

8. Nantahala Power & Light Co. v. Thornburg, 106 S. Ct. 2349, 2360 (1986) (emphasis in original).

9. Sinclair Machine Prod. Inc., 498 A.2d 696, 699 (N.H. 1985).

10. Pike County Light & Power Co. v. Public Util. Comm'n, 77 Pa. Commw. 268, 273-74, 465 A.2d 735, 737-38 (1983).

11. Mississippi Indus. v. FERC, 808 F.2d 1525 (D.C. Cir. 1987), cert. denied, 108 S. Ct. 500 (1987).

12. Middle S. Energy, Inc., 31 F.E.R.C. ¶ 61,305 (1985) [hereinafter Opinion No. 234].

13. Middle S. Servs., Inc., 32 F.E.R.C. ¶ 61,425 (1985) [hereinafter Opinion No. 234-A].

14. Mississippi Indus. v. FERC, 822 F.2d 1104 (D.C. Cir. 1987).

15. Systems Energy Resources, Inc., 41 F.E.R.C. ¶ 61,238 (1987) [hereinafter Opinion No. 292].

detail the reasons underlying its method, which was to equalize nuclear capacity costs, but not other costs, among its operating affiliates.

The allocation of costs was provided for in the Unit Power Sales Agreement among the MSU companies. That agreement, which deals with transactions in interstate commerce, was found to be within the FERC's jurisdiction and subject to modification by the FERC. In finding FERC jurisdiction, the court relied heavily on *Nantahala Power & Light v. Thornburg*, observing that the:

FERC's allocation of Grand Gulf's costs and capacity, like the setting of entitlement percentages in *Nantahala Power & Light*, does not set a sale price, but does directly affect costs and, consequently, wholesale rates. We cannot disregard the Supreme Court's clear and timely message that [the] FERC's jurisdiction under such circumstances is unquestionable.¹⁶

The court rejected claims that the FERC was in effect asserting jurisdiction over a generating facility in contravention of section 201(b) of the Federal Power Act,¹⁷ that it was compelling purchases of power and energy contrary to the Act,¹⁸ that it unlawfully interfered with the jurisdiction of state regulatory authorities,¹⁹ and that it intruded upon the authority of the Securities and Exchange Commission under the Public Utilities Holding Company Act to regulate the MSU system as a registered holding company.²⁰

In a related matter, the New Orleans City Council denied an immediate pass through of the Grand Gulf costs assigned by the FERC to New Orleans Public Service, Inc. (NOPSI) (one of the MSU operating companies). The NOPSI sought injunctive relief in the U.S. District Court, alleging federal preemption. The district court dismissed the NOPSI's claims on grounds of abstention. Its decision was at first reversed by the Fifth Circuit²¹ but was subsequently affirmed by order of that court on reconsideration withdrawing the portion of its opinion finding abstention inappropriate and substituting a very different analysis. The Fifth Circuit observed that "*Nantahala* recognizes that retail rates need not necessarily be increased to reflect the corresponding increase in wholesale rates set by [the] FERC."²²

In another decision, issued in December 1987, the Fifth Circuit again denied a NOPSI effort to enjoin any action by the New Orleans City Council that would force the NOPSI's shareholders to absorb Grand Gulf costs that had been allowed by the FERC.²³ The court observed that the City Council had not yet acted to disallow any part of the NOPSI's request for a permanent rate increase. In refusing to enjoin the City Council, the court relied on representations by the attorney for the City Council at oral argument that the City Council accepted the FERC order as a "given" and that it was focusing on

16. *Mississippi Indus. v. FERC*, 808 F.2d 1525, 1542 (D.C. Cir. 1987).

17. *Id.* at 1543-45.

18. *Id.* at 1545-47.

19. *Id.* at 1547-50.

20. *Id.* at 1550-51.

21. *New Orleans Pub. Serv., Inc. v. Council of New Orleans*, 782 F.2d 1236 (5th Cir. 1986).

22. *New Orleans Pub. Serv., Inc. v. Council of New Orleans*, 798 F.2d 858, 860 (5th Cir. 1986), *cert. denied*, 107 S. Ct. 1910 (1987).

23. *New Orleans Pub. Serv., Inc. v. Council of New Orleans*, 833 F.2d 583 (5th Cir. 1987).

ways that the NOPSI could reduce its other costs at the retail level such as by making off-system sales or achieving operational economies.²⁴ The court stated: "This court is not prepared to assume that the New Orleans City Council will go beyond its express statements and its legal authority. Should the New Orleans City Council act contrary to statements made in this Court, NOPSI could make use of estoppel and similar legal arguments."²⁵

In a case similar to the Grand Gulf controversy, the FERC dealt with the allocation of costs by means of a unit power agreement under a holding company system agreement in *AEP Generating Co.*²⁶ The case involved a request for a declaratory order filed by Kentucky Power Company (KEPCO), an operating company member of the AEP System, asking the FERC to declare that the AEP System Interconnection Agreement required it to purchase unit power from Indiana & Michigan Electric Company's (another operating company member of the AEP System) Rockport plant. The Kentucky Public Service Commission (PSC) had disallowed in Kentucky Power's retail rates the cost of the unit power purchase on prudence grounds, based on a finding that Kentucky Power could have obtained power from the System at the lower capacity equalization charges in the Interconnection Agreement. The FERC disagreed with this interpretation of the Interconnection Agreement and declared that it has "exclusive, pre-emptive authority over the allocation of the costs of generating capacity on the AEP system among the individual members."²⁷

In order to prevent further disagreements, the Commission ordered the AEP companies to add provisions to the Interconnection Agreement clarifying obligations to meet native load and defining "affiliate." The Commission observed:

Section 35.1(a) of the Commission's regulations, which implements section 205(c) of the Federal Power Act, requires public utilities to file full and complete rate schedules setting forth all rates and charges, the classifications, practices, rules and regulations affecting such rates and charges, and all contracts which affect or relate to the foregoing.²⁸

An interesting and important aspect of the order is the following statement: "Even assuming that we were forcing KEPCO to purchase Rockport capacity and, thus, "enlarge" its generating facilities, we are empowered to do so under the Federal Power Act."²⁹

The opinion on rehearing repeated the strong assertion of FERC jurisdiction (whether exclusive or primary is not entirely clear) to determine the meaning of an interstate pool or holding company system agreement. Where the Kentucky PSC determined that KEPCO had imprudently accepted an allocation of new coal capacity because lower-cost power was available to it

24. *Id.* at 586.

25. *Id.* at 587.

26. *AEP Generating Co.*, 38 F.E.R.C. ¶ 61,243, *reh'g denied*, 39 F.E.R.C. ¶ 61,158 (1987), *petition for review pending sub nom.* Kentucky Pub. Serv. Comm'n v. FERC, No. 87-3643 (6th Cir. filed July 10, 1987).

27. *AEP Generating Co.*, 38 F.E.R.C. ¶ 61,243, at 61,823 (1987).

28. *Id.* at 61,822 (footnotes omitted).

29. *Id.* at 61,826 n.22 (citations omitted).

through the AEP Interconnection Agreement's capacity equalization mechanism, the Kentucky PSC acted outside its jurisdiction; the so-called "*Pike County*" exception to federal preemption is inapplicable.³⁰

The Commission observed that because AEP is operated as a wholly-integrated system, and operating companies do not have autonomy with regard to planning and adding new generation, a "prudence" inquiry is inappropriate. According to the FERC, the real question is not KEPCO's "prudence," but where costs have been allocated within the System in a reasonable manner.³¹

The Commission also held that provisions of a tariff or jurisdictional bulk power agreement should be construed so as to avoid "unfair, unusual, absurd, or improbable results," if a reasonable construction is consistent with the language used.³²

As with the MSU Grand Gulf situation, AEP failed in efforts to obtain a federal court injunction of state proceedings involving the issue of disallowance in retail rates of the unit power transaction. The U.S. Court of Appeals for the Sixth Circuit issued an unpublished opinion on March 24, 1986, in *American Electric Power Co. v. Kentucky Public Service Commission*,³³ in which it affirmed a dismissal on abstention grounds of a challenge to the state commission order when an appeal from that order was pending in state courts. The court relied in part on the fact that AEP would have an adequate opportunity to raise the federal claims in the pending state court action.

AEP fared better, however, in obtaining declaratory and injunctive relief against the Public Service Commission of West Virginia's (WVPSC) efforts to scrutinize a transmission equalization agreement (TEA) among the AEP operating companies. In *Appalachian Power Co. v. Public Service Commission*,³⁴ the court ruled that the FERC has exclusive jurisdiction over the agreement, which allocates costs among the companies pursuant to a formula that accounts for the demands each company places on the System. The WVPSC sought to review the prudence of the TEA and had filed a motion with the FERC requesting the FERC to limit its consideration to whether the terms of the agreement were just and reasonable and to determine what regulatory body had power to assess the "prudence" of the agreement. The FERC responded by ruling that state commissions did not have authority to consider the prudence issue.³⁵

In its opinion, the Fourth Circuit relied on the U.S. Supreme Court's *Nantahala* decision and found that the *Pike County* distinction was not appropriate, stating:

On a practical level, the *Pike County* inquiry is meaningless here because there is no alternative source of power for APC to choose other than that available

30. AEP Generating Co., 39 F.E.R.C. ¶ 61,158, at 61,629-30 (1987).

31. *Id.* at 61,627.

32. *Id.* at 61,626.

33. The issuance of opinion was noted at 787 F.2d 588 (1986), *cert. denied*, 107 S. Ct. 1910 (1987).

34. *Appalachian Power Co. v. Public Serv. Comm'n*, 812 F.2d 898 (4th Cir. 1987).

35. *American Elec. Power Serv. Corp.*, 32 F.E.R.C. ¶ 61,363 (1985), *reh'g denied*, 37 F.E.R.C. ¶ 61,001 (1986).

through the AEP system, and the only access to that power is over the EHV lines whose costs are allocated by the TEA. Because the essence of the *Pike County* inquiry is whether a particular choice was wise, the lack of choice here makes such an inquiry an empty one. In the *Nantahala* case, . . . the Supreme Court recently recognized a similar futility in invoking the *Pike County* analysis. In *Nantahala*, the North Carolina Utilities Commission, in setting retail rates, claimed authority to apportion a particular source of "entitlement" power between two affiliated utilities after [the] FERC already had made a fair allocation of that power in setting wholesale rates. The Court rejected as inapplicable the *Pike County* line of authority in part because there was only one available source for the particular "entitlement" energy at issue in *Nantahala*.³⁶

The opinion contains extensive discussion of the rationale in support of the federal preemption, among which is the following passage:

Contrasted with this broad public interest protected by federal regulation is the narrower state public interest advanced by PSC regulation. . . . Because the prudence inquiry is inseparable from an inquiry into the TEA's justness and reasonableness, [the] FERC and the PSC would be making identical, independent inquiries regarding the merits of the TEA but from the perspective of different public interests. It is possible that [the] FERC and the PSC would reach conflicting conclusions regarding the impact of the agreement on their respective publics. Only [the] FERC, as a central regulatory body, can make the comprehensive public interest determination contemplated by the FPA and achieve the coordinated approach to regulation found necessary in *Attleboro*.³⁷ No single state commission has the jurisdiction, and neither can it be expected to have the competence or inclination, to make this broad determination.³⁸

An order that deals with the FERC's jurisdiction and the filed rate doctrine was issued in *North Carolina Municipal Power Agency No. 1 v. Duke Power Co.*,³⁹ where the FERC held that it has jurisdiction to consider a complaint that cancellation losses may not properly be charged under the provisions of a formula rate in interconnection agreements. Duke had argued that the agreements require that the dispute be submitted to arbitration. The Commission disagreed, stating:

We agree with Duke that the agreements generally contemplate that any disputes between the parties over provisions in the agreements be initially submitted to arbitration. Nevertheless, and notwithstanding our general inclination to encourage arbitration of disputes, we decline to order arbitration in this proceeding for the reason set forth below.

In *South Carolina Generating Company* . . . and *Orange and Rockland Utilities, Inc.* . . . we addressed whether utility companies are permitted to recover Account No. 407 expenses and stated in both that "such losses are particularly inappropriate for inclusion in automatically adjusting formula rates prior to Commission approval." In light of this clear policy, submitting the instant dispute to arbitration would be a waste of time and resources and would only serve to delay our resolution of the matter.⁴⁰

36. *Appalachian Power*, 812 F.2d at 903 (citations omitted).

37. *Public Utils. Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927).

38. *Appalachian Power*, 812 F.2d at 905.

39. *North Carolina Mun. Power Agency No. 1 v. Duke Power Co.*, 40 F.E.R.C. ¶ 61,138, *reh'g denied*, 41 F.E.R.C. ¶ 61,060 (1987), *petition for review pending sub nom. Duke Power Co. v. FERC*, No. 87-1781 (D.C. Cir. filed Dec. 17, 1987).

40. *North Carolina Mun. Power*, 40 F.E.R.C. at 61,404.

The Commission's rationale was that the filed rate, as interpreted by the FERC, would ultimately control, irrespective of what an arbitrator might find.

The Commission's order in *Florida Power & Light Co.*⁴¹ granted a request for declaratory order sought by Florida Power & Light Company and asserted exclusive jurisdiction over the terms and conditions applicable to the wheeling to other electric utilities of power generated by qualifying cogeneration and small power production facilities. The Florida Public Service Commission had issued a rule stating that it had authority to regulate charges, terms and conditions for transmission service which occurs in intrastate commerce. The FERC relied on findings in a prior order,⁴² which in turn relied upon *FPC v. Florida Power & Light Co.*,⁴³ that transportation over a transmission grid which is used in interstate commerce establishes the FERC's jurisdiction because there is a commingling of energy that is in interstate commerce. The Commission stated that its authority to set the rates, terms and conditions of transmission arrangements is "exclusive, nondelegable and may not be disclaimed," and therefore it denied a request to exercise what is characterized as a "purported discretion to disclaim jurisdiction" that had been requested by an intervenor, the National Association of Regulatory Utility Commissioners.⁴⁴

In *Iowa-Illinois Gas and Electric Company and Sherrard Power System*,⁴⁵ the Commission denied a request for disclaimer of jurisdiction over the electric facilities of an electric distribution company, Sherrard Power System, which was proposed to be merged into Iowa-Illinois Gas and Electric Company through securities issuances. In declining to disclaim jurisdiction, the Commission ruled that, because Sherrard had transmission facilities that were used to transmit electric energy received in the stream of interstate commerce in bulk to its local distribution facilities, they did not fall within the "local distribution facilities" exemption.⁴⁶ The Commission further found that the fact that Sherrard was a full requirements customer of Iowa-Illinois did not interrupt the interstate stream. The Commission granted the alternative request of the applicants for approval of the merger and associated acquisition.

In *San Diego Gas and Electric Co. v. Alamito Co.*,⁴⁷ the Commission found that a two-step merger transaction required prior Commission authorization pursuant to section 204 of the Federal Power Act. The first step was a merger of Alamito Company into Alamito Holdings, Inc., a wholly-owned subsidiary of Osceola Energy, Inc. Immediately prior to this first step Osceola cancelled Alamito Holdings' only liability, the common stock of Alamito Holdings held by Osceola. In the second step Alamito Company was merged into Osceola, the surviving corporation. Thereafter Osceola changed its name to Alamito. In analyzing the transaction for purposes of jurisdiction, the

41. *Florida Power & Light Co.*, 40 F.E.R.C. ¶ 61,045 (1987).

42. *Florida Power & Light Co.*, 29 F.E.R.C. ¶ 61,140, at 61,291-92 (1984).

43. *FPC v. Florida Power & Light Co.*, 404 U.S. 453, 461-63 (1972).

44. *Florida Power & Light Co.*, 40 F.E.R.C. at 61,121.

45. *Iowa-Illinois Gas and Elec. Co. and Sherrard Power Sys.*, 35 F.E.R.C. ¶ 61,287 (1986).

46. See *FPC v. East Ohio Gas Co.*, 338 U.S. 464, 469-71 (1950).

47. *San Diego Gas and Elec. Co. v. Alamito Co.*, 38 F.E.R.C. ¶ 61,241 (1987).

Commission considered the transaction as a whole, observing that there is a general rule that an agency "may disregard corporate form in the interest of public convenience, fairness, or equity" and added that the inquiry is "a question of whether statutory purposes would be frustrated by corporate form."⁴⁸ In concluding that section 204 approval was required, the Commission observed that prior to the merger Alamito had an interest in two generating stations, had contracts to sell electricity at wholesale, and had \$530 million in long-term debt obligations; after the merger Alamito had the same interest in the two generating stations, had the same contracts to sell electricity at wholesale, and had increased its long-term debt by \$150 million. The Commission went on to comment that the merger of the power sales contracts for the wholesale sales may also have been subject to the prior authorization requirements of section 203, citing *Hartford Electric Light Co. v. FPC*,⁴⁹ and directed Alamito to file for authorization pursuant to section 203 as well as section 204.

Idaho Power Co. and Utah Power & Light Co.,⁵⁰ involved a transmission service contract between Idaho Power Company and Pacific Power & Light Company (PP&L), pursuant to which PP&L makes facility charge payments to Idaho for transmission facilities used to transfer energy from one PP&L system area to another. Among the issues presented was whether the terms and conditions for the sale and transfer of ownership of a substation were subject to Part II jurisdiction. The contract dispute concerns whether PP&L is required to construct terminal and transformation facilities and to transfer ownership in such facilities. A state court suit for alleged breach of contract had been brought. The Commission found that it does not have exclusive jurisdiction over the breach of contract claims, but that certain of the issues may be within its primary jurisdiction. After observing that the question of whether it should exercise primary jurisdiction was discretionary,⁵¹ the FERC found that a "compelling case" existed here because (1) "the disputed contractual terms are technical in nature, and require our extensive experience in the electric power industry for proper interpretation," (2) the questions require uniformity of interpretation, and (3) "legal and policy questions critical to our regulatory programs" are raised.⁵² Accordingly, the contract interpretation issue was set for hearing.

The Commission accepted for filing rate schedules submitted in *Golden Spread Electric Cooperative*,⁵³ and rejected claims by Southwestern Public Service Company that Golden Spread, a cooperative bulk power supplier, is not subject to the FERC's jurisdiction because either (1) it is not a public utility because it has no electric facilities or (2) its members are financed through the Rural Electrification Administration (REA) and are subject to exclusive jurisdiction by REA.

48. *San Diego Gas and Elec.*, 38 F.E.R.C. at 61,778.

49. *Hartford Elec. Light Co. v. FPC*, 131 F.2d 953 (2d Cir. 1942), cert. denied, 319 U.S. 741 (1943).

50. *Idaho Power Co. and Utah Power & Light Co.*, 39 F.E.R.C. ¶ 61,032 (1987).

51. *Idaho Power Co.*, 39 F.E.R.C. at 61,092 (citing *United States v. Western R.R. Co.*, 352 U.S. 59 (1956) and *Arkansas La. Gas Co. v. Hall*, 7 F.E.R.C. ¶ 61,175 (1979)).

52. *Idaho Power Co.*, 39 F.E.R.C. at 61,092.

53. *Golden Spread Elec. Coop.*, 39 F.E.R.C. ¶ 61,322 (1987).

II. FILINGS BY NON-TRADITIONAL UTILITIES

In *Citizens Energy Corp. (Citizens I)*,⁵⁴ the FERC addressed the issue of how it would apply sections 203 and 205 of the Federal Power Act to a non-profit corporation that engaged in brokering wholesale electric power transactions between willing electric utility buyers and sellers.

Citizens Energy Corporation's (Citizens) plan was to provide electricity subsidies to the poor and elderly. To do so, Citizens proposed to purchase wholesale electric power and energy from utilities with available excess generating capacity and to resell such power and energy to electric utilities at rates which would be economically attractive to the purchasing utilities. Citizens would place any revenues earned on such transactions, net of any transmission charges and Citizens expenses, into a fund. Distributions from the fund would then be made to needy electric customers of the selling and purchasing utilities.

Citizens petitioned the FERC to declare its transactions exempt from sections 203 and 205 of the Federal Power Act, or alternatively, to grant waiver of the FERC's regulations as they would apply to the proposed transactions. The FERC declined to find that the transactions would be non-jurisdictional since Citizens clearly would be engaged in interstate wholesale sales. The FERC also declined to follow its line of cases exempting institutional owner/investors engaged in leveraged-lease transactions from FPA jurisdiction finding that, unlike the sale and leaseback cases, in Citizens' case, the FERC would have no other party (i.e., the utility lessee) over which to assert authority involving clearly jurisdictional sales. The FERC did, however, grant liberal waivers of its regulations based upon a finding that Citizens would not be "a typical public utility" since it would be "engaged in the sale of electric energy on a non-profit basis and has neither shareholders nor invested capital," and that the proposed transactions would potentially "promote a more efficient market for the sale of energy and power."⁵⁵ Interestingly, the FERC's "efficiency" finding was based on Citizen's rates would be market-based rather than cost-based. The FERC also found that Citizens' transactions would "provide financial benefits to utilities by reducing those utilities' uncollectible accounts, and provide assistance to needy consumers of electricity." However, the FERC reserved the right to review Citizens' rates under the FPA's "just and reasonable" standard at the time which the rates would be submitted.

In *Citizens Energy Corp. (Citizens II)*,⁵⁶ the Commission was given its first opportunity to rule on the just and reasonableness of a proposed Citizens transaction. Citizens proposed to purchase power from the Utah Municipal Power Agency (UMPA) at an initial rate equal to UMPA's incremental cost plus 4 mills/kWh, adjusted for losses, and resell the energy on an interruptible basis to the Department of Water and Power of the City of Los Angeles (LADWP) at a rate based upon LADWP's lowest quote for economy energy

54. *Citizens Energy Corp.*, 35 F.E.R.C. ¶ 61,198 (1986).

55. *Cliff's Elec. Serv. Co.*, 32 F.E.R.C. ¶ 61,372 (1985).

56. *Citizens Energy Corp.*, 36 F.E.R.C. ¶ 61,332 (1986).

from alternate suppliers, i.e., LADWP's decremental costs based upon its purchase costs, assuming Citizens would recover its purchase power costs and also recover a 1 mill/kWh adder plus a reasonable contribution to a Citizens Special Assistance Fund. The Fund would distribute amounts to be shared equally between needy customers in Los Angeles' and UMPA's service areas. The Fund would be administered by public service organizations such as the Salvation Army.

When the case was considered at a public meeting on September 10, 1986, the Commission on a 2-2 vote was unable to reach agreement on approval of the transaction under the Federal Power Act. However, to avoid any "unintended legal affects under the Act" the FERC's final decision approved the proposed rates.

Traditionally, the FERC allows sellers to charge rates based upon either (1) the seller's fixed cost or (2) a price set midway between the seller's incremental cost and the purchaser's decremental cost. Here, however, the FERC for the first time approved a transaction based upon the purchaser's decremental costs. The FERC reasoned that: (1) absent Citizens' involvement, the transactions between UMPA and LADWP would be unregulated by the FERC (since neither utility is jurisdictional) and therefore it would be inappropriate "to look beyond Citizens' role as a middleman"; and (2) a reasonable share of Citizens' profits would be actually channeled back to ratepayers of Los Angeles and UMPA in equal parts. The Commission also recognized the non-profit nature of Citizens' transactions.

In Commissioner Trabandt's concurring opinion, the Commissioner expressed substantial concern over the precedential impact of the FERC setting rates at the purchaser's decremental costs since by definition this would retain all the benefits of the transaction for the seller. With regard to the FERC's argument finding that an equitable allocation results since Citizens allocates a portion of the profits to LADWP's needy retail residential customers, Commissioner Trabandt noted that "while this may be a reasonable way to further social equities, it directly conflicts with traditional ratemaking equities." He specifically noted that the FERC was approving a mechanism which "diverts monies to retail customers" which could result in unreasonable wholesale rates, and that "rate equity demands that those customers who pay for the facilities should share proportionately in all the benefits derived from those facilities."⁵⁷ "In effect," Commissioner Trabandt argued,

the Commission has reasoned that it is obligated to regulate this transaction as jurisdictional, but in so doing it will only regulate Citizens' rate in terms of its 'profit.' And, since the profits of Citizens are channeled back to ratepayers in the form of charitable assistance, the rates are reasonable under the Federal Power Act.⁵⁸

The implications of this, Trabandt reasoned, "would mean that *any* rate charged by Citizens in *any* jurisdictional transaction would *ipso facto* be reasonable, provided that the profits were channeled back ultimately to needy

57. *Citizens Energy Corp.*, 36 F.E.R.C. at 61,790.

58. *Id.*

ratepayers, and *all* transactions would be approved.”⁵⁹ Commissioner Trabant acknowledged, however, that the majority opinion indicated that a different standard could apply where Citizens’ supplier and/or purchaser were FERC jurisdictional utilities. Commissioner Trabant also suggested that in the future Citizens allocate a proportional amount of its Fund to wholesale customers.

III. MARKET-BASED PRICING

During the period covered by this report, the Commission has indicated a willingness to move in the direction of market-based pricing. The Commission may be moving gingerly away from a direct and explicit relationship between costs and rates to accepting rates based, at least in part, on the competitive market.

The first case involved EUA Power Corporation (EUA Power), a subsidiary of Eastern Utilities Associates, which was established to purchase the shares of the Seabrook Nuclear Generating Project from a number of utilities. In Docket No. EL85-46, EUA Power sought a declaratory order from the Commission that would allow it to sell its share of the Seabrook power to non-affiliated buyers at market-based prices. EUA Power had purchased its ownership interest at a fraction of the original cost to the initial owners. After the Commission set the matter for hearing, a settlement was reached and approved by the Commission.⁶⁰ In approving a subsequent settlement involving the purchase of an additional ownership share, the Commission spelled out what it meant by “market-based prices.”⁶¹ Those prices are ones negotiated with a purchaser, but subject to a cap. The cap, designed to require EUA Power to share cost advantages at least equally with its customers, is the midpoint between EUA Power’s cost-based rates for unit power from Seabrook No. 1 and Montaup’s (an EUA Power affiliate) cost-based rates for unit power from Seabrook No. 1. Rates for sales to Montaup itself are more severely limited.

Another case involved the Western Systems Power Pool (WSPP). The WSPP submitted rates labelled as experimental “to determine whether generation and transmission facilities in certain western states can be used more efficiently in an environment of broader information exchange and more flexible pricing.”⁶² In that order, the Commission found that “wholesale electricity markets are becoming more competitive due to economic and technological changes.”⁶³ Unlike the earlier Southwest Experiment,⁶⁴ the WSPP Agreement provides for transmission service on a voluntary basis, not a mandatory basis.

Under the WSPP Agreement, flexible pricing would apply to economy energy, unit commitment and firm system capacity and/or energy sale or

59. *Id.* (emphasis in original).

60. EUA Power Corp., 35 F.E.R.C. ¶ 61,187 (1986).

61. EUA Power Corp., 36 F.E.R.C. ¶ 61,017, at 61,039 n.8 (1986).

62. Pacific Gas & Elec. Co., 38 F.E.R.C. ¶ 61,242, at 61,781 (1987).

63. *Id.*

64. Public Serv. Co., 25 F.E.R.C. ¶ 61,469 (1983), *reh’g denied*, 27 F.E.R.C. ¶ 61,154 (1984).

exchange transactions, and to the marketing of transmission services. Despite the flexible pricing, ceilings could be applied related to costs associated with the highest fully allocated cost resource among the participants in the experiment during the prior year and a floor of 1 mill/kWh for transmission service reservation would be established. An "electronic bulletin board" would be utilized to facilitate daily exchanges of buy and sell quotes.

The Commission described its interest in the experiment as three-fold: increasing efficiency, promoting competition, and promoting coordination.

In accepting the rates for filing, the Commission required that "at least seventy-five percent of the benefits attributable to an increase in the level of coordination sales under the WSPP, not already reflected in the utility's current requirements rates, are flowed through to the utility's requirements rate-payers."⁶⁵ The Commission also required an "independent and objective analysis of the data collected."⁶⁶

In *Baltimore Gas & Electric Co.*,⁶⁷ the Commission accepted for filing Baltimore Gas and Electric Co.'s (BG&E) proposal to sell monthly its unutilized share of the transmission capability of the Pennsylvania—New Jersey—Maryland (PJM) Interconnection 500-kV EHV transmission system for importing energy from the west. Bidding would be by open telephone auction. A price cap would be based on the savings which could be realized if the PJM member with the highest alternative cost were able to use BG&E's transmission entitlement to import western power.

A similar proposal had been rejected by the Commission fifteen months earlier.⁶⁸ In accepting the later proposal, the Commission found two differences to be dispositive: (1) open bids are being used in lieu of sealed bids and (2) BG&E has explained how its auction proposal would affect efficiency. The Commission accepted the earlier-rejected proposal to waive the requirement of cost support data. "The Commission may depart from cost-of-service ratemaking when necessary or appropriate to serve a legitimate statutory objective of the Federal Power Act (FPA), i.e., greater efficiency and coordination."⁶⁹ In effect, the Commission accepted the buyer's avoided cost as establishing the upper bound of the zone of reasonableness and took comfort because BG&E will not have any significant degree of market power.

In *Regulation of Independent Power Producers*, Docket No. EL87-67-000 (September 25, 1987), the Commission announced a technical conference "to receive comments on initiatives involving independent power producers[IPP]." An IPP was defined as a generating entity (other than a qualifying facility) that lacks significant market power and that is independent of any local electric utility where the IPP provides service. With respect to market-based pricing, the Commission specifically inquired into whether IPP's should be permitted to establish rates based on competitive bidding or rate negotiations on "workably competitive markets."

65. *Pacific Gas*, 38 F.E.R.C. ¶ 61,242, at 61,799.

66. *Id.* at 61,800.

67. *Baltimore Gas & Elec. Co.*, 40 F.E.R.C. ¶ 61,170 (1987).

68. *Baltimore Gas & Elec. Co.*, 35 F.E.R.C. ¶ 61,150, *reh'g denied*, 36 F.E.R.C. ¶ 61,148 (1986).

69. *Baltimore Gas*, 40 F.E.R.C. ¶ 61,170, at 61,538 (citations omitted).

IV. THE MOBILE-SIERRA DOCTRINE

In two cases, an administrative law judge (ALJ) and the Commission refused to abrogate contracts under section 206(a) of the Federal Power Act. In another, the Tenth Circuit Court of Appeals adopted a decision by the District of Columbia Circuit which held that a rate established under section 206 does not become effective until a compliance filing is accepted by the Commission.

First, in *Gulf States Utilities Co. v. Southern Co. Services*,⁷⁰ an ALJ refused to abrogate or modify contracts under section 206(a) of the Federal Power Act on the basis of non-cost factors related to the buyer's poor financial condition. In 1982, Gulf States Utilities Company (GSU) entered into a Unit Power Sales Agreement with Southern Company Services, Inc. (Southern) to purchase 1,000 MW of power per year beginning June 1985, and an Interconnection Contract which contained rate schedules for short term or emergency power sales. The Agreements were filed with the Commission in June 1982, but by mid-1983 GSU realized that it would not need all the capacity of Southern's coal-fired units due to changing economic conditions.⁷¹ The parties agreed to some amendments designed to reduce GSU's obligations and submitted a settlement to the Commission which was approved in March 1984.

By 1985, the circumstances worsened for GSU. Demand in GSU's service area had decreased and declining oil and gas prices made Southern's capacity less competitive. In 1986, the Texas and Louisiana state regulatory commissions denied GSU pass through of the capacity payments to its ratepayers.⁷²

After unsuccessful negotiations, GSU filed a complaint requesting the Commission to relieve it from its obligations to Southern on the grounds of unforeseen changed circumstances which rendered the agreements unjust and unreasonable under section 206(a) of the Federal Power Act. Specifically, GSU argued that (1) a reduction in its load, the resulting lack of need for Southern's capacity and the existence of more competitive alternatives constituted unforeseen changed circumstances which rendered the agreements unjust and unreasonable, (2) the contracts were not producing the expected benefits of lower cost displacement energy since the cost of Southern's power exceeded GSU's unavowed costs, (3) it has suffered a substantial financial loss under the contracts which has placed it on the brink of bankruptcy, and (4) Southern's relatively larger size renders it better able to absorb the losses.⁷³

Both parties agreed that the "just and reasonable" standard rather than the *Sierra-Mobile* public interest standard applied.⁷⁴ The judge, however, deemed it appropriate to investigate the contractual rates and charges under both the just and reasonable standard and the Commission's "indefeasible

70. *Gulf States Utils. Co. v. Southern Co. Servs.*, 39 F.E.R.C. ¶ 63,026 (1987).

71. *Id.* at 65,137.

72. *Id.* at 65,138.

73. *Id.* at 65,149.

74. *Id.* at 65,142.

right" to change any rate or charge which is contrary to the public interest.⁷⁵ The major issue before the judge was whether the just and reasonable standard under section 206(a) extends beyond the question of whether the sales rates are cost-based to a consideration of the type of non-cost factors relied upon by GSU.

The Initial Decision answered that question in the negative. The judge found that (1) the only change that was unforeseeable was the refusal of the state regulatory commissions to permit pass through of the capacity costs and their refusal to provide rate relief for GSU's River Bend Nuclear Plant,⁷⁶ (2) the failure of the state commissions to grant rate relief for River Bend, and not the Southern contracts, was the principal cause of GSU's financial difficulties,⁷⁷ (3) GSU was not guaranteed perpetual benefits under the agreements,⁷⁸ and (4) the comparative size of the utilities was not relevant to the consideration of the just and reasonableness of the rate under section 206(a).⁷⁹ The judge concluded that under circumstances such as these, the public interest did not require a purchaser to be relieved of its contractual obligations on the basis of non-cost factors.⁸⁰

Second, in *Utah Power & Light Co.*,⁸¹ the Commission affirmed an Initial Decision that refused to allow Utah Power & Light Company (Utah Power) to raise its rates for firm wheeling service under two fixed rate contracts with the U.S. Department of Energy, Western Area Power Administration. The Utah State Division of Public Utilities treated the wholesale wheeling revenues as a credit to the retail cost of service. Utah Power argued, therefore, that the low fixed wholesale rates resulted in less of a credit and hence greater retail rates which constituted an "excessive burden to other customers" under the criterion of the *Sierra* case.⁸²

The Commission rejected Utah Power's interpretation of the "excessive burden" criterion. It agreed with the Initial Decision that the "excessive burden" criterion was "not intended to serve as the escape clause for those utilities fortunate enough to be able to transfer their fixed rate contract losses directly to other customers."⁸³ Instead, the Commission determined what the impact of the fixed rate contracts on Utah Power's other customers would be if the state commission abandoned the revenue credit approach and Utah Power was required to absorb the costs.⁸⁴ Under this analysis, the Commission found that the wholesale contracts would create a .77% revenue deficiency when measured against total revenues.⁸⁵ This would not impose an

75. *Id.*

76. *Id.* at 65,149.

77. *Id.* at 65,153-55.

78. *Id.* at 65,149-53.

79. *Id.* at 65,155.

80. *Id.* at 65,156.

81. *Utah Power & Light Co.*, 41 F.E.R.C. ¶ 61,308 (1987).

82. *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956).

83. *Utah Power & Light Co.*, 41 F.E.R.C. ¶ 61,308, at 61,808 (quoting *Utah Power & Light Co.*, 33 F.E.R.C. ¶ 63,001, at 65,008 (1985)).

84. *Utah Power & Light Co.*, 41 F.E.R.C. ¶ 61,308, at 61,808.

85. *Id.*

excessive burden on Utah Power's other customers because Utah Power presented no evidence that this deficiency would impair its ability to continue to provide service.⁸⁶ Finally, the Commission rejected the contention that section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA)⁸⁷ required a cost of service standard for electric service.⁸⁸

Third, in *Public Service Co. v. FERC*,⁸⁹ the Tenth Circuit Court of Appeals followed the holding of the District of Columbia Circuit in *Electric District No. 1 v. FERC (ED-1)*,⁹⁰ that rates are not "fixed" under section 206(a), and thus may not become effective until the Commission accepts the utility's compliance filing. The court rejected attempts by both the Commission and the utility to confine *ED-1* to the facts of that case. It noted that the D.C. Circuit refused to assess on a case-by-case basis the question of whether the ratemaking principles set forth in an initial order were sufficient to inform the ratepayers of the filed rates.⁹¹ Consequently, the court interpreted the D.C. Circuit as having adopted a "hard and fast" rule that section 206 rates are fixed when a compliance filing is accepted.⁹²

V. COST OF SERVICE AND RATE DESIGN

A. Prudence

In *Violet v. FERC*,⁹³ the U.S. Court of Appeals for the First Circuit upheld a decision by the Commission allowing New England Power Company to recover 100% of its losses on the abandoned Pilgrim No. 2 generating unit. The decision to abandon the unit had been made in September 1982 by the lead participant in the unit, Boston Edison Company (Edison). The Massachusetts Department of Public Utilities had ruled in an Edison retail rate proceeding that Edison had acted imprudently in not making that decision fifteen months earlier in July 1980 and had disallowed all costs incurred during the fifteen months.

The prudence issue decided in the Edison retail rate proceeding came before the FERC in a proceeding where New England Power Company requested recovery of its losses as a joint owner of Pilgrim No. 2 and where New England Power had stipulated that it would not challenge the state finding that Edison was imprudent.

The initial decision in the *New England Power* case held that New England Power had acted imprudently in signing a joint ownership agreement in 1972 which gave it no right to sue Edison for imprudent management of Pilgrim No. 1—i.e., for not cancelling the unit in July 1980—except for a "deliberate violation" of the agreement, which the decision to continue the project

86. *Id.*

87. 16 U.S.C. § 2621(d)(1) (1982).

88. *Utah Power & Light Co.*, 41 F.E.R.C. ¶ 61,308, at 61,809.

89. *Public Serv. Co. v. FERC*, 832 F.2d 1201 (10th Cir. 1987).

90. *Electric Dist. No. 1 v. FERC*, 774 F.2d 490 (D.C. Cir. 1985).

91. *Public Service*, 832 F.2d at 1223.

92. *Id.* at 1223-24.

93. *Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986).

beyond July 1980 clearly was not.⁹⁴ The Commission, reversing the initial decision, found that whether New England Power had acted prudently in signing the joint ownership agreement was irrelevant since New England Power's actions in supporting continuation of the project until it was cancelled were prudent regardless of the terms of the joint ownership agreement.⁹⁵ The court, in affirming that theory, found that the record contained "little if any evidence that . . . NEP would have pursued any different course in respect to Pilgrim II had a different contract been in place."⁹⁶ The court refused to conclude, "in the absence of more tangible evidence of a causal link between the allegedly imprudent contract and the costs NEP now seeks to recover," that "the Commission erred as a matter of law in refusing to focus on the events predating July 1, 1980."⁹⁷

In *Montaup Electric Co.*,⁹⁸ the Commission found that another joint owner of Pilgrim No. 2, Montaup Electric Company, was entitled to recover 100% of its losses on the project. In the *Montaup* case, the same ALJ who had recommended disallowance of New England Power Company's costs incurred in the fifteen months from July 1980 until the project was cancelled in September 1982 decided that Montaup's costs incurred during the same fifteen months should be disallowed for the same reason; namely, that Montaup, like New England Power, had imprudently signed away its right to sue Edison in executing the joint ownership agreement in 1972.⁹⁹ The Commission, in reversing the *Montaup* initial decision found that it had to deal with the question which it did not deal with in *New England Power*—whether it was imprudent to enter into the joint ownership agreement—because in *Montaup*, unlike *New England Power*, all of Montaup's expenditures on Pilgrim No. 2 were at issue instead of only those made in the period July 1980 through September 1982. The Commission found that Montaup lacked bargaining power to persuade Edison to change the joint ownership agreement and was not imprudent in signing it. The Commission also concluded, as it had in *New England Power*, that there was nothing to indicate that Montaup would have acted any differently even if Montaup had been able to negotiate better terms with Edison.

In *Union Electric Co.*,¹⁰⁰ the Commission found some of Union Electric Company's investment in the Callaway nuclear plant to be imprudent in a proceeding on Union Electric's filing to include the plant in wholesale rate base as plant in service. The state commissions in Missouri and Illinois had already made prudence disallowances in decisions on filings to include the plant in retail rate base. The ALJ in the wholesale proceeding had found that Union Electric had failed to dispel the doubts created by the findings of those commissions that various costs had been imprudently incurred.¹⁰¹ The Com-

94. *New England Power Co.*, 27 F.E.R.C. ¶ 63,057 (1984).

95. *New England Power Co.*, 31 F.E.R.C. ¶ 61,047 (1985).

96. *Violet*, 800 F.2d at 283.

97. *Id.*

98. *Montaup Elec. Co.*, 39 F.E.R.C. ¶ 61,379 (1987).

99. *Montaup Elec. Co.*, 31 F.E.R.C. ¶ 63,003 (1985).

100. *Union Elec. Co.*, 40 F.E.R.C. ¶ 61,046 (1987).

101. *Union Elec. Co.*, 35 F.E.R.C. ¶ 63,076 (1986).

mission affirmed the findings made in the initial decision.

In *New England Power Co.*,¹⁰² an ALJ found that New England Power Company had acted prudently in supporting the continuation of Seabrook No. 2, on which construction stopped in March 1984. The ALJ rejected arguments by intervenors that New England Power had acted imprudently in not pressing the lead participant to cancel Seabrook No. 2 earlier than it did and recommended that New England be allowed to recover all of its losses on the project over ten years. This initial decision together with the initial decision in the second phase of the case reported herein under "Cancelled Plant" are pending before the Commission.

B. Cancelled Plant

In *Montaup Electric Co.*,¹⁰³ (also discussed in this report under "Prudence"), the Commission allowed Montaup to recover its losses on the Pilgrim No. 2 project over five years, with the unamortized balance to be excluded from rate base.¹⁰⁴ The Commission found that the five year period, which Montaup had proposed and which the Staff had supported, "will allow for a write-off of the Pilgrim II loss as quickly as possible while mitigating the impact on ratepayers."¹⁰⁵ The rate impact of the amortization was an increase of 1.3%.¹⁰⁶

*New England Power Co.*¹⁰⁷ presents the question of whether the Commission should change its current policy of allowing abandonment losses to be recovered without being included in rate base during the period of recovery. New England Power has proposed inclusion of the unamortized losses in rate base and the Staff has proposed an even division of abandonment losses between shareholders and ratepayers. The initial decision, following the Commission's instructions in setting the hearing, contains only findings of fact and no policy recommendations.

C. Fuel Charges

The most significant fuel charge developments involved the pricing of affiliated coal purchases. In *Public Service Co. v. FERC*,¹⁰⁸ the court affirmed the Commission's determination in Opinion No. 133 that "the reasonableness of the cost of coal purchased from an affiliate should be determined by a comparison to the prices of coal available from nonaffiliated suppliers."¹⁰⁹ The court found the Commission's reasoning in support of a market price standard to be reasonable because of the Commission's "lack of jurisdiction over ratemaking in the coal industry, its lack of expertise in the field, and the perceived benefits of allowing the competitive market to determine coal

102. *New England Power Co.*, 37 F.E.R.C. 63,010 (1986).

103. *Montaup Elec. Co.*, 39 F.E.R.C. ¶ 61,379 (1981).

104. *Montaup Elec. Co.*, 39 F.E.R.C. ¶ 61,379 (1987).

105. *Montaup Elec. Co.*, 39 F.E.R.C. at 62,230.

106. *Id.*

107. *New England Power Co.*, 38 F.E.R.C. ¶ 63,020 (1987).

108. *Public Serv. Co. v. FERC*, 832 F.2d 1201, 1211-12 (10th Cir. 1987).

109. *Public Serv. Co.*, 17 F.E.R.C. ¶ 61,123 (1981).

prices."¹¹⁰ The court, however, cautioned that "[i]n affirming the Commission on this point, we do not presume to settle the matter by declaring the market price standard superior in every instance."¹¹¹

In *Ohio Power Co.*,¹¹² the Commission applied the market test from Opinion No. 133. The Commission there found Ohio Power's affiliated coal prices for Martinka coal to be in excess of market value and ordered refunds back to the date the rate increases in that case became effective.

In reaching this finding, the Commission determined the prices of comparable coal. Among other things, the Commission looked at sulfur content, contract vintages, transportation costs and mine type.¹¹³ The Commission also developed a relevant market based on a fifty-mile radius from the Ohio Power plant which consumed the affiliated coal. The Commission recognized that drawing a line at 50 miles or 100 miles "obviously involves an element of discretion."¹¹⁴ Further, in applying its market test, the Commission used a weighted-average non-affiliated coal price. The Commission thus found Ohio Power's coal costs excessive because such costs were above the weighted-average price, though below the costs of some non-affiliated coal.¹¹⁵ Finally, the Commission established a benchmark based on market prices to govern Ohio Power's future fuel charges for Martinka coal.¹¹⁶

A fuel issue arose in another context in *Southern California Edison Co. v. FERC*.¹¹⁷ The D.C. Circuit affirmed a Commission order requiring the company to remit to its wholesale customers refunds received by the utility from its fuel suppliers between 1974 and 1981. This case is significant because the company had a fixed-rate (and not a cost-of-service) fuel clause during that time period. Such fixed-rate fuel clauses establish a "proxy" for actual fuel charges and are not adjusted after the billing period to reflect actual costs as does a cost-of-service fuel clause. Thus, the court found that billings under fixed clauses are not inviolable and that refunds could be ordered at a later point in time.¹¹⁸

D. Taxes

Major changes in the tax area at the Commission have arisen because of the Tax Reform Act of 1986. That Act, among other things, reduced the Federal corporate income tax rate from 46% to 34%, effective July 1, 1987, reduced the usefulness of accelerated depreciation, and eliminated investment tax credits.

In response to the reduction in the Federal corporate income tax rate, the Commission has required filing utilities to modify test period data to comply

110. *Public Service*, 832 F.2d at 1213.

111. *Id.* at 1214.

112. *Ohio Power Co.*, 39 F.E.R.C. ¶ 61,098 (1987).

113. *Ohio Power*, 39 F.E.R.C. at 61,280-83.

114. *Id.* at 61,202.

115. *Id.* at 61,283.

116. *Id.* at 61,286.

117. *Southern Cal. Edison Co. v. FERC*, 805 F.2d 1068 (D.C. Cir. 1986).

118. *Southern Cal. Edison*, 805 F.2d at 1071.

with the lower rate.¹¹⁹ The Commission also issued Order No. 475¹²⁰ which deals with the tax rate change on a generic basis. In Order No. 475, the Commission established an abbreviated filing procedure that most electric utilities could use to reduce the tax rate component of their rates, without filing a full Federal Power Act section 205(e) rate filing. In order to entice such voluntary abbreviated filings, the Commission threatened to institute formal investigations of the *overall* rates of companies that do not voluntarily file.

Another issue which arises because of the tax rate change involves deferred tax make-up provisions. Under the higher forty-six percent tax rate, most electric utilities possessed insufficient amounts in their deferred tax accounts to meet their future tax liabilities. Because of the significant drop in the corporate tax rate, many companies now possess excessive amounts in those deferred tax accounts. While the Commission in Order No. 475 did not require electric utilities to flow through any excessive deferred taxes to their ratepayers, that result is inevitable as it is required by 18 C.F.R. § 35.25 of the Commission's regulations.

E. Construction Work In Progress

As a result of *Mid-Tex Electric Cooperative v. FERC*,¹²¹ which remanded the Commission's 1983 Construction Work in Progress (CWIP) rule,¹²² there has been a flurry of activity at the Commission on CWIP during 1986 and 1987. First, on February 27, 1986, the Commission issued Order No. 448¹²³ as an interim rule and requested comments. In Order No. 448, the Commission did not change the substance of Order No. 298. It allowed electric utilities to include in rate base, in addition to all pollution control and fuel conversion CWIP, up to fifty percent of all remaining CWIP. The Commission did, however, require the filing utility to provide additional information to allow the Commission to assess the "double whammy"¹²⁴ issue at an early stage. Also, if an intervenor made a "concrete substantial showing" of irreparable injury resulting from rate base treatment of CWIP, the Commission stated that it would consider a variety of options, depending upon the circumstances. On June 30, 1987, this interim rule was affirmed in *Mid-Tex Electric Cooperative v. FERC*.¹²⁵

On June 18, 1987, the Commission issued Order No. 474,¹²⁶ a final rule

119. See, e.g., *West Texas Utils. Co.*, 38 F.E.R.C. ¶ 61,138 (1987).

120. Order No. 475, *Electric Utilities; Rate Changes Relating to Federal Corporate Income Tax Rates for Public Utilities*, III F.E.R.C. Stats. & Regs. ¶ 30,752, 52 Fed. Reg. 24,987 (1987).

121. *Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327 (D.C. Cir. 1985).

122. Order No. 298, [1982-1985 Regs. Preambles] F.E.R.C. Stats. & Regs. ¶ 30,455, 48 Fed. Reg. 24,323 (1983).

123. Order No. 448, III F.E.R.C. Stats. & Regs. ¶ 30,689, 50 Fed. Reg. 7774 (1986).

124. Double whammy arises "when a wholesale customer embarks on a construction program of its own in order to supply itself with all or part of its future power requirement." *Mid-Tex Elec. Coop.*, 773 F.2d at 357. If that customer pays for CWIP of another utility, then he would get hit with the double whammy of financing two construction programs, at least in part.

125. *Mid-Tex Elec. Coop. v. FERC*, 822 F.2d 1123 (D.C. Cir. 1987).

126. Order No. 474, *Electric Rates; Construction Work in Progress; Anticompetitive Implication*, III F.E.R.C. Stats. & Regs. ¶ 30,751, 52 Fed. Reg. 23,948 (1987).

on CWIP. In Order No. 474, the Commission again allowed electric utilities to include in rate base 100% of pollution control and fuel conversion CWIP and fifty percent of other CWIP. The Commission also: (1) established filing requirements to allow it to quickly determine whether the inclusion of CWIP in rate base may create a price squeeze (section 35.26(g)(i)); (2) provided a mechanism for intervenors to obtain preliminary relief upon a showing of irreparable harm (section 35.25(g)(2)); and (3) required that CWIP be allocated to customer classes on the basis of "forward looking allocation ratios" (section 35.26(c)(4)).

F. End Result Test

The "end result" test from *FPC v. Hope Natural Gas Co.*,¹²⁷ experienced a rebirth in 1987. In an en banc decision, with four judges dissenting, the D.C. Circuit in *Jersey Central Power & Light Co. v. FERC*,¹²⁸ remanded a rate case to the Commission for an end result hearing.

This case began when Jersey Central submitted a rate increase filing at the Commission. Jersey Central sought rate base inclusion of costs associated with the cancelled Fork River nuclear plant. In support, Jersey Central alleged that for four years it had been unable to pay any dividends on common stock and that it was on the verge of being forced into bankruptcy. In the suspension order, the Commission summarily rejected Jersey Central's request to include cancelled plant costs in rate base, relying on prior precedent.

On appeal, a panel of the D.C. Circuit first affirmed and then later on rehearing remanded the Commission's orders.¹²⁹ However, both decisions were subsequently vacated.

In an en banc decision of a split court, the Commission was required to hold an end result hearing. The court first analyzed Supreme Court precedent and stated that:

[t]he teaching of these cases is straightforward. In reviewing a rate order courts must determine whether or not the end result of that order constitutes a reasonable balancing, based on factual findings, of the investor interest in maintaining financial integrity and access to capital markets and the consumer interest in being charged non-exploitative rates.¹³⁰

More significantly, the court also stated that "an order cannot be justified simply by a showing that each of the choices underlying it was reasonable; those choices must still add up to a reasonable result."¹³¹ The court further found that a remand was required because Jersey Central made detailed allegations of financial harm which tracked the *Hope* requirements, but were ignored by the Commission.¹³²

127. *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

128. *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168 (D.C. Cir. 1987).

129. *See Jersey Cent. Power & Light Co. v. FERC*, 768 F.2d 1500 (D.C. Cir. 1985); *Jersey Cent. Power & Light Co. v. FERC*, 730 F.2d 816 (D.C. Cir. 1984).

130. *Jersey Central*, 810 F.2d at 1177-78.

131. *Id.* at 1178.

132. *Id.*

G. Rate of Return

In the second annual proceeding for evaluating rate of return on a generic basis for jurisdictional electric utilities, the Commission issued Order No. 442¹³³ determining that for the base year ending June 30, 1985, the average cost of common equity was 15.36% and the average "ratemaking rate of return" was 14.37%. The Commission described the rate of return as that which, when applied to rate base, allows the electric utility to provide investors the opportunity to obtain their effective required return. The Commission also established a quarterly indexing procedure to update cost estimates and to set benchmark equity returns for use in individual rate cases. As to the "ratemaking rate of return" concept, however, the Commission on rehearing in Order No. 442-A¹³⁴ determined not to adopt such concept in light of unresolved questions and an inadequate record. In the third annual generic rate of return proceeding, the Commission issued Order No. 461¹³⁵ determining an average cost of common equity of 13.05% for the base year ending June 30, 1986. The Commission again adopted a quarterly indexing procedure,¹³⁶ but eliminated from such procedure the fifty-basis-point cap utilized in the first two annual proceedings. While the benchmark rate of return established in this proceeding was to have been accorded a rebuttable presumption status, the Commission decided that it would remain advisory, i.e., to serve as a guide to companies and intervenors in individual rate cases and as a reference point for the Commission in its deliberations.

In a number of cases,¹³⁷ in light of the substantial time that had elapsed since the rates first became effective and in light of the decline in capital costs that had occurred since the record was closed, the Commission, relying upon the changes in U.S. Treasury bond yields, established a "second tier" rate of return to be applied prospectively.

In *Yankee Atomic Electric Co.*,¹³⁸ a case involving investigations of the cost-of-service formula rates of the three Yankee nuclear generating companies, the Commission found the equity allowances of all three companies to be excessive and set their rates of return on equity at twelve percent. The Commission also concluded that as a condition to their continued use of cost-of-service formula rates, each company would be required to include in its rate schedule an "equity reopener" provision establishing procedures whereby motions to institute hearings and refund obligations would be entertained periodically to address any issue concerning the return on common equity.

133. Order No. 442, *Generic Determination of Rate of Return on Common Equity for Public Utilities*, III F.E.R.C. Stats. & Regs. ¶ 30,677, 51 Fed. Reg. 343 (1986).

134. Order No. 442-A, III F.E.R.C. Stats. & Regs. ¶ 30,702, 51 Fed. Reg. 22,505 (1986).

135. Order No. 461, III F.E.R.C. Stats. & Regs. ¶ 30,722 (1986), 52 Fed. Reg. 11 (1987).

136. See 18 C.F.R. § 37.9(d) (1987) (table of the quarterly benchmark rates of return).

137. *Union Elec. Co.*, 40 F.E.R.C. ¶ 61,046 (1987); *South Carolina Generating Co.*, 40 F.E.R.C. ¶ 61,116 (1987); *New York State Elec. and Gas Corp.*, 37 F.E.R.C. ¶ 61,151 (1986).

138. *Yankee Atomic Elec. Co.*, 40 F.E.R.C. ¶ 61,372 (1987).

H. Price Squeeze/Antitrust

In *Southern California Edison Co.*¹³⁹ the FERC delivered its most comprehensive analysis of price squeeze issues to date. In this case, Edison's rate to its wholesale customers exceeded its rate to comparable retail customers for 11½ months of a 43½ month locked-in period. During the balance of the locked-in period, wholesale rates were lower than comparable retail rates. The ALJ granted refunds to the wholesale customers based on the 11½ month difference in rates and refused Edison's request for an offset for the balance of the locked-in period. Refunds were limited, though, to the amount which could be realized by reducing Edison's rate of return from the level set in Opinion No. 62¹⁴⁰ to the lower level of the zone of reasonableness established in Opinion No. 62. Both sides filed exceptions.

On exception, the Commission conducted a broad review of price squeeze issues and its policies. The Commission first restated its current policy of phasing price squeeze cases by hearing rate level issues first and price squeeze issues second. The Commission also restated its policy of determining the existence of a price squeeze on a rate of return comparison based on test period data rather than actual experience. This is to be the policy even if actual results are available.

The ALJ had divided the locked-in period into four sub-periods which reflected the retail rate for comparable service at various times. The Commission affirmed, but it rejected Edison's off-set claim because the purpose of anti-trust law (which price squeeze involves) is to protect competition and not competitors. Since competition was harmed by the price squeeze, the later preference for wholesale customers could not cure the earlier harm to competition caused by the earlier retail rate preference. However, while price squeeze is an antitrust claim, the Commission's remedial authority under the Federal Power Act is limited to curing any unjust discrimination that exists. Thus, a determination must be made in each case that the discrimination was undue. The nature of the Commission's remedial authority was also addressed. The Commission held that based on the Supreme Court's opinion in *FPC v. Conway*,¹⁴¹ it could only reduce rates as a remedy by the difference between the authorized rate of return and the lower limit of the previously determined zone of reasonableness.

Most significantly, the Commission terminated its previously established rebuttable presumption that a retail-wholesale rate disparity established a prima facie showing of anticompetitive effect. While the Commission applied the former doctrine in this case, it held that henceforward the wholesale customer would have the burden of coming forward with evidence to establish a prima facie showing "that the alleged price squeeze will have either an actual or potential competitive effect."¹⁴² The Commission stated that while the util-

139. *Southern Cal. Edison Co.*, 40 F.E.R.C. ¶ 61,371 (1987).

140. *Southern Cal. Edison Co.*, 8 F.E.R.C. ¶ 61,198 (1979), *reh'g denied in part and granted in part*, Opinion No. 62-A, 10 F.E.R.C. ¶ 61,260 (1980), *affirmed sub nom. Cities of Anaheim v. FERC*, 669 F.2d 799 (D.C. Cir. 1981).

141. *FPC v. Conway*, 426 U.S. 271 (1976).

142. *Southern Cal. Edison*, 40 F.E.R.C. at 62,127.

ity continues to carry the ultimate burden of showing the rate increase to be not unjust and unreasonable and not unduly discriminatory or preferential, the customer must make an affirmative showing of anticompetitive effect. This must be a market analysis along traditional antitrust lines although the Commission eschewed any intent to institute comprehensive antitrust proceedings. The Commission stated: "What we do intend, however, are price squeeze proceedings which focus on objective criteria in examining the harm, or potential harm, to competition which may arise out of a disparity between wholesale and retail rates."¹⁴³ Commissioner Trabandt issued a vigorous dissent on this issue.

VI. OTHER RATE ISSUES

In *Southwestern Electric Power Co. v. FERC*,¹⁴⁴ the court refused to accept the FERC's characterization of a filing as a changed rate rather than an initial rate where the filing extended an existing service to a new customer. The FERC's rehearing order¹⁴⁵ acknowledged that it was "redrawing the line between changed and initial rates."¹⁴⁶ The court found that the FERC had not given a clear and coherent explanation for its departure from prior practice and remanded the case to the FERC. In the court's view the utility had made a "colorable claim" that the service was not identical to the existing service being offered other customers,¹⁴⁷ and it labelled as a "quick brush off" the FERC's finding that the proposed service was offered at "similar, but slightly different, rates" to the other customers.¹⁴⁸ As a possible standard the court suggested that "proposed service can be deemed the 'same' as existing service only if it would be reasonable to apply the rates covering that existing service to the proposed service."¹⁴⁹ Judge Mikva, in dissent, argued that the FERC had clearly stated its criterion and therefore had acceptably altered the line between initial and changed rates.

The Commission's denial of an effective date prior to the filing date was upheld in *City of Girard v. FERC*.¹⁵⁰ Girard, a partial requirements customer of Kansas Gas and Electric Company, sought to become a full requirements customer after the loss of its generating capability. It argued, first, that it was entitled unilaterally to switch to the existing full requirements rate schedule, and second, that the FERC should have granted waiver of the section 205 notice requirement to allow retroactive effectiveness of the utility's later filing to serve Girard as a full requirements customer.

The Commission twice ruled that the customer's attempt to change to

143. *Id.* at 62,168.

144. *Southwestern Elec. Power Co. v. FERC*, 810 F.2d 289 (D.C. Cir. 1987).

145. *Southwestern Elec. Power Co.*, 34 F.E.R.C. ¶ 61,160 (1986).

146. *Southwestern Elec. Power*, 34 F.E.R.C. at 61,272.

147. *Southwestern Elec. Power*, 810 F.2d at 293.

148. *Southwestern Elec. Power*, 34 F.E.R.C. at 61,271.

149. *Southwestern Elec. Power*, 810 F.2d at 293 (footnote omitted).

150. *City of Girard v. FERC*, 790 F.2d 919 (D.C. Cir. 1986).

another rate schedule was barred by the filed rate doctrine.¹⁵¹ The court agreed, stating that the City's position would undermine "the very heart of the filed rate doctrine."¹⁵² The previously approved partial requirements rate schedule provided for emergency and supplemental service, and no change in these terms could be effective without Commission approval; specific agreement of the customer to the prior terms was not necessary.

Avoiding the issue of whether the Commission may waive the filing requirement to permit a retroactive effective date in the absence of agreement by the parties, the court affirmed the FERC's refusal to find good cause for the waiver. It referred to the FERC's "long-standing general policy" to find good cause only when the parties have agreed to a prior effective date, and found that the FERC had applied the general policy in this case.¹⁵³ It therefore affirmed the FERC's grant of the waiver of notice only for the period to which both parties assented.

The obligation of member companies to provide generating capacity under the American Electric Power System Interconnection Agreement was clarified by the FERC in *AEP Generating Co.*¹⁵⁴ The controversy involves the efforts of the Kentucky Public Service Commission to avoid the impact of a newly constructed plant on ratepayers served at retail by Kentucky Power Company (KEPCO), an AEP member company. Jurisdictional aspects of the dispute are discussed in Section I of this Report. After the Kentucky Commission rejected KEPCO's proposed fifteen percent direct ownership of the Rockport plant, AEP Generating Company filed a unit power sales agreement with the FERC.¹⁵⁵ KEPCO, to resolve its rights and obligations as purchaser under the unit power sales agreement, filed a petition for declaratory order with the FERC.¹⁵⁶ The cases were consolidated and set for hearing on three issues involving the System Interconnection Agreement.¹⁵⁷ A settlement of all cost-of-service and coal issues was approved.¹⁵⁸ The ALJ answered "none of the above" to the three questions the Commission set for hearing: (1) whether the Interconnection Agreement, as implemented by the AEP companies, establishes an obligation on the part of the members to supply sufficient capacity to meet their native load requirements over time; (2) whether such an obligation is inherent in the AEP system; or (3) whether a member company may become capacity deficient and purchase its capacity shortfall from the other members under the Interconnection Agreement on a permanent basis.¹⁵⁹

The FERC affirmed the ALJ's findings and added its own commentary on the relationship between the Interconnection Agreement members. It

151. *Kansas Gas & Elec. Co.*, 26 F.E.R.C. ¶ 61,122, at 61,307, *reh'g granted*, 27 F.E.R.C. ¶ 61,015 (1984).

152. *City of Girard*, 790 F.2d at 922 (emphasis in original).

153. *Id.* at 925.

154. *AEP Generating Co.*, 38 F.E.R.C. ¶ 61,243 (1987).

155. *AEP Generating Co.*, 36 F.E.R.C. ¶ 61,226 (1986).

156. *Kentucky Power Co.*, 36 F.E.R.C. ¶ 61,227 (1986).

157. *AEP Generating Co.*, 36 F.E.R.C. ¶ 61,226 (1986); *Kentucky Power Co.*, 36 F.E.R.C. ¶ 61,227 (1986).

158. *AEP Generating Co.*, 37 F.E.R.C. ¶ 61,044 (1986).

159. *Kentucky Power Co.*, 37 F.E.R.C. ¶ 63,015 (1986).

stated that the AEP member companies have an obligation to provide capacity to meet the system's need, that the assignment of that obligation among the members is based on a variety of factors, and that the ability of each member to meet its native load is relevant to that assignment, even if a member's surplus or deficiency status with respect to native load may be different from its status with respect to the AEP pool. The FERC also stated that principles of mutuality are inherent in any pooling arrangement, and that over time, the sharing of burdens and benefits should balance to the extent practicable. Reliance on purchases at average-cost capacity equalization charges in lieu of providing generating capacity, the Commission pointed out, would result in subsidization of non-building member companies by those who add capacity at current prices. For the same reasons, and because the capacity equalization charge does not track capacity costs as accurately as the unit power sales agreement, the Commission held that KEPCO does not have an option of relying indefinitely on capacity equalization charges as an alternative to purchase of capacity. Under the circumstances of the case, KEPCO does not have the option of refusing an assignment by AEP of a portion of new capacity for the system. The Commission interpreted the Interconnection Agreement to allow unit sales as well as direct ownership. To avoid future uncertainty with respect to the obligations of member companies to install or have under firm contract sufficient capacity for their native loads, the FERC ordered AEP to add to the Interconnection Agreement an explicit statement of the obligation and a definition of the term "affiliate."

Allocation of the cost of Grand Gulf and other nuclear capacity of the Middle South Utilities system was considered by the Court of Appeals for the District of Columbia Circuit¹⁶⁰ and by the FERC on remand.¹⁶¹ In its earlier decision on Grand Gulf issues, the Commission reviewed the Grand Gulf Unit Power Sales Agreement (UPSA) and the 1982 Middle South System Agreement.¹⁶² It found that the UPSA's assignment of the costs of the Grand Gulf Nuclear Generating Station among the four member companies of the Middle South System was not just and reasonable. Assignment as of the escalated costs of the Grand Gulf plant without reallocation of other nuclear resources, the FERC concluded, would produce undue discrimination in the operation of the System Agreement. To correct these disparities in wholesale rates, the FERC ordered an equalization of installed system nuclear investment costs among the four member companies based on demand responsibility, stressing that the Middle South System is an integrated system. On appeal, a panel of the District of Columbia Circuit initially affirmed the FERC decision. A dissent to the panel decision, adopted by the panel on reconsideration, found that the Commission had not adequately explained its criteria for determining undue discrimination or its reasons for the particular cost equalization it

160. *Mississippi Indus. v. FERC*, 808 F.2d 1525, *reh'g granted*, 814 F.2d 773 (en banc) (as to cost equalization and allocation issues), *reh'g vacated*, 822 F.2d 1103 (en banc), *remanded*, 822 F.2d 1104 (to the FERC on cost issues), *cert. denied*, 108 S. Ct. 500 (1987) (as to jurisdictional issues). The jurisdictional issues are discussed in Part I of this report.

161. *System Energy Resources, Inc.*, 41 F.E.R.C. ¶ 61,238 (1987).

162. *Middle S. Energy, Inc.*, 31 F.E.R.C. ¶ 61,305, *reh'g denied*, 32 F.E.R.C. ¶ 61,425 (1985).

chose. It therefore remanded to the Commission to reconsider those matters.¹⁶³

In Opinion No. 292, the FERC explicitly stated the rationale which it said underlay its 1985 decision, and reaffirmed the specific capacity equalization it had earlier adopted. It explained its historic focus on demand responsibility as the proper basis for allocation of capacity investment, distinguishing it from the equalization of capacity cost per megawatt, on which the court placed emphasis. The FERC stated that satisfaction of demand is the measure of benefit to the customer: "A cost equalization approach that fails to consider demand would ignore the very determinant that controls the need for various levels of capacity."¹⁶⁴ The explicit criteria, the FERC stated, are (1) that each operating utility should contribute investments to meet the capacity needs of the system in the long term, and (2) that each operating utility should share in the overall capacity costs of the system in rough proportion to the benefits it receives (i.e., that its demand is met) from that system.¹⁶⁵ The FERC also responded to the court's suggestion that only Grand Gulf costs be reallocated or that all generating capacity costs be equalized. The first approach, according to the FERC, would impose additional costs without restoring the rough equalization of production costs that it said was an objective of the System Agreement, and the equalization of all generation was unnecessary, the FERC felt, because non-nuclear generation costs were already roughly comparable.

In *Ocean State Power*,¹⁶⁶ the FERC approved initial rates filed by Ocean State Power for unit sales to Boston Edison Company, New England Power Company, Montaup Electric Company and Newport Electric Corporation. Ocean State is a partnership partially owned by a number of electric utilities, including Eastern Utilities, NEES and Newport Electric Corporation. Under the arrangement, Ocean State would sell capacity and energy from a generating unit which would be owned and constructed by Ocean State. The rate proposal was unusual in that it included four provisions designed to encourage the efficient construction and operation of the unit: (1) a construction cost ceiling; (2) a provision permitting the purchasers to withdraw from the agreement if significant construction delays occurred; (3) imposition of penalties if the facility failed to achieve a specific availability factor and/or design rating; and (4) incentive payments when Ocean State's plant exceeded a certain availability factor.

The FERC found that the incentive package, which differed from typical unit sales contracts which require purchasers to pay all fixed costs no matter how efficiently the plant is constructed and operated, was just and reasonable and provided incentives to Ocean State to operate its plant as efficiently as possible. The proposed rates were silent on what rate of return on equity would be achieved by Ocean State. The FERC therefore conditioned its

163. Contemporaneously with the panel reconsideration order, the Circuit vacated its earlier grant of en banc rehearing. *Mississippi Indus.*, 822 F.2d at 1104.

164. *System Energy Resources, Inc.*, 41 F.E.R.C. ¶ 61,238, at 61,616 (1987).

165. *Id.* at 61,617.

166. *Ocean State Power*, 38 F.E.R.C. ¶ 61,140 (1987).

acceptance upon Ocean State filing a return on equity component prior to the in-service date of the facility, and its approval thereof.

VII. TRANSMISSION

In *Florida Power & Light Co.*,¹⁶⁷ the Commission held that it had exclusive jurisdiction to determine the reasonableness of terms and conditions of transmission (wheeling) service on behalf of qualifying facilities. Florida Power & Light Company (FP&L) sought a declaratory order from the FERC that would inform the Florida Public Service Commission that the Florida rules, which purported to give Florida the jurisdiction over wheeling terms and conditions, were preempted under the Federal Power Act. The FERC agreed, on the same basis that it had previously determined that the Florida Commission was preempted from establishing the *rates* for wheeling service.¹⁶⁸ As in the prior order, the FERC declined to address the issue whether the state has the authority to direct a utility to provide transmission service in the first instance.

In dicta, the D.C. Circuit in *Associated Gas Distributors v. FERC*,¹⁶⁹ relating to the FERC's open access natural gas transportation findings in Order No. 436, rejected the contention that prior court of appeals decisions barred the FERC from imposing an open-access condition on electric utilities in all circumstances. The court's discussion suggested that the FERC might be able to use open access conditions for transmission service as a remedy for anticompetitive or discriminatory conduct.¹⁷⁰

In a case involving the appropriate allocation of transmission system costs, the Ninth Circuit affirmed a FERC determination that a utility's 46 KV and 69 KV transmission facilities should be "rolled-in" with the utility's other transmission facility costs associated with higher voltage capacity for the purpose of allocating costs to the utility's wholesale sales customers.¹⁷¹ The court held that there was substantial evidence for the FERC to find that the lower voltage facilities were integrated with the higher voltages facilities, and that the "rolled-in" allocation method was consistent with the FERC precedent.

In *Baltimore Gas & Electric Co. (BG&E)*,¹⁷² the FERC finally gave a green light to BG&E to auction off a portion of its entitlement to use the Pennsylvania-New Jersey-Maryland (PJM) transmission system. The potential bidders are the other joint owners of the PJM transmission system. The FERC had previously rejected BG&E's auction proposal because of, inter alia, a lack of demonstrated efficiency gains and the use of a sealed bid arrangement. Under the new proposal that the FERC approved, BG&E explained how its proposal would enhance efficiency (it will improve regional efficiencies among the PJM members) and agreed to an open bid method in lieu of sealed

167. *Florida Power & Light Co.*, 40 F.E.R.C. ¶ 61,045 (1987).

168. *Florida Power & Light Co. and Florida Pub. Serv. Comm'n*, 29 F.E.R.C. ¶ 61,140 (1984).

169. *Associated Gas Distribs. v. FERC*, 824 F.2d 981 (1987).

170. *Associated Gas*, 824 F.2d at 999.

171. *Sierra Pac. Power Co. v. FERC*, 793 F.2d 1086 (1986).

172. *Baltimore Gas & Elec. Co.*, 40 F.E.R.C. ¶ 61,170 (1987).

bids. The FERC also granted BG&E's request for waiver of the filing of cost-of-service data.

The FERC, as of December 31, 1987, has taken no action in response to its Notice of Inquiry, Docket No. RM85-17-000, which solicited oral and written comments on suggestions for improving the services and the pricing of those services in the electric industry. Included in the list of services was transmission service. It is expected that the FERC will address transmission service issues in 1988.

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