

REPORT OF THE COMMITTEE ON ELECTRIC UTILITY REGULATION

I. FERC ADMINISTRATIVE ACTIVITY

A. *Transmission Pricing Policy*

In its “Inquiry Concerning the Commission’s Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act,”¹ the Federal Energy Regulatory Commission (FERC or Commission) issued a policy statement designed to allow greater transmission pricing flexibility than allowed under prior FERC policies.

The policy statement sets forth five principles to be used in evaluating transmission pricing proposals. Transmission pricing:

- (1) “[M]ust meet the traditional revenue requirement” - embedded cost;
- (2) “[M]ust reflect comparability” - charging others on a basis comparable to that which the transmitting utility effectively charges itself for the same service;
- (3) “[S]hould promote economic efficiency” - efficient expansion, siting, use and dispatch by reflecting marginal costs to the extent practicable;
- (4) “[S]hould promote fairness” - mitigate hardships arising out of pricing reform and prevent cross-subsidies; and
- (5) “[S]hould be practical” - easy to administer and understand.²

The Commission will also entertain “non-conforming” pricing proposals that exceed the traditional revenue requirement. Such proposals must include a complete discussion of how they take account of the five pricing principles, and must reflect comparability. A non-conforming proposal will be summarily rejected unless it includes an open-access comparability tariff. The Commission will also summarily reject a non-conforming proposal that does not include information showing how it both (i) produces overall consumer benefits exceeding those that would be associated with a conforming proposal; and, (ii) promotes competitive bulk power markets.

B. *Access to Transmission Services: Section 211 Proceedings*

The pace of section 211 filings³ at the FERC accelerated during 1994. The FERC issued its first orders requiring transmission by non-public utilities⁴ and clarified that section 211 would apply to qualified facilities under

1. [1991-1995 Regs. Preambles] F.E.R.C. STATS & REGS. ¶ 31,005 (1994).

2. *Id.* at 31,141-44.

3. Federal Power Act § 211, 16 U.S.C. § 824j (1994) [hereinafter FPA].

4. *Tex-La Elec. Coop. of Texas, Inc.*, 67 F.E.R.C. ¶ 61,019, 69 F.E.R.C. ¶ 61,269 (1994) (investor-owned utility located within the electrically separate Electric Reliability Council of Texas); *Minnesota Mun. Power Agency v. Southern Minn. Mun. Power Agency*, 66 F.E.R.C. ¶ 61,223, 68 F.E.R.C. ¶ 61,060 (1994). The Nebraska Public Power District has challenged in federal district court section 211 jurisdiction over a state power agency; the challenge is based on the 10th Amendment and Guarantee Clause of the U.S. Constitution.

the Public Utility Regulatory Policies Act.⁵ The Commission also established that its transmission pricing policy would be the same for section 201(e) and section 211 transmission, and that the heart of that policy would be comparability.⁶ This unified approach appears to further discourage the use of preemptive section 205 transmission filings in response to section 211 applications.⁷ Lastly, the Commission clarified several important jurisdictional and procedural issues, smoothing the path for further section 211 applications.

The first jurisdictional step in a section 211 proceeding is a good faith request and reply. An applicant for a section 211 order must first make a good faith request for transmission services at least sixty days prior to its application to the FERC; transmitting utilities must provide a good faith reply within sixty days of receipt of the request.⁸ To determine compliance, the Commission looks to whether the parties have met, exchanged points of view, and provided the information requested.⁹ The Commission determines the required amount and detail of exchanged information by examining how much information a utility needs,¹⁰ and whether a utility has used the information already provided.¹¹ Mere disagreement with the other party's position is no basis to find a bad faith request or reply.¹²

5. Order No. 569, *Interpretation and Amendment Clarifying Exemption to Qualifying Facilities From the Federal Power Act*, III F.E.R.C. STATS. & REGS. ¶ 31,001 (1994) (amending 18 C.F.R. § 292.601).

6. *Inquiry Concerning The Commission's Pricing Policy For Transmission Services Provided By Public Utilities Under the Federal Power Act*, III F.E.R.C. STATS. & REGS. ¶ 31,004 (1994) (adding 18 C.F.R. § 2.22).

7. See *Old Dominion Elec. Coop. v. Delmarva Power & Light Co.*, 68 F.E.R.C. ¶ 61,169, at 61,769 (1994) ("We will not countenance attempts . . . to avoid the section 211 proceeding by making a subsequent section 205 filing.").

8. FPA §§ 211(a), 213(a), 16 U.S.C. §§ 824j(a), 824l(a) (1994); 18 C.F.R. § 2.20 (1994); *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 by the Energy Policy Act of 1992*, III F.E.R.C. STATS. & REGS. ¶ 30,975 (1993).

9. *Tex-La*, 67 F.E.R.C. ¶ 61,019, at 61,053 (exchange of information and points of view), *final order*, 69 F.E.R.C. ¶ 61,269 (1994); *Minnesota Mun. Power Agency*, 66 F.E.R.C. ¶ 61,223 (1994) (information fairly exchanged), *final order*, 68 F.E.R.C. ¶ 61,060 (1994); *Florida Mun. Power Agency v. Florida Power & Light Co.*, 65 F.E.R.C. ¶ 61,125 (1993) (parties met on many occasions, and FMPPA provided requested data), *final order*, 67 F.E.R.C. ¶ 61,167 (1994).

10. *Tex-La*, 67 F.E.R.C. ¶ 61,019, at 61,053 (good faith request because the transmitting utility, a long-term requirements supplier to requesting party, already had much information concerning the network transmission request).

11. *Id.* (good faith request because transmitting utility had enough information to prepare its own draft agreements); *Minnesota Mun. Power Agency*, 66 F.E.R.C. ¶ 61,114, at 61,189 (good faith reply because transmitting utility responded with concrete proposals and explanations); *Florida Mun. Power Agency*, 65 F.E.R.C. ¶ 61,125, at 61,616-17 (1993) (good faith request because transmitting utility had enough data to provide two reports).

12. *Tex-La*, 67 F.E.R.C. at 61,053 (good faith request even though not in accordance with transmitting utility's desired terms and conditions); *Minnesota Mun. Power Agency*, 66 F.E.R.C. ¶ 61,223, ¶ 61,019, at 61,510-11 (good faith reply even though proposed rate higher than that desired by requesting utility).

So far, the Commission has not found any case of a bad faith reply¹³ and has found only two cases of a bad faith request, or at least changed requests. In *Old Dominion Electric Cooperative v. Delmarva Power & Light Co.*, the Commission confined the scope of the application to the scope of the written request.¹⁴ The FERC rejected Old Dominion's claim that Delmarva should have "intuited" from subsequent negotiations the broader intended request.¹⁵ However, in *Minnesota Municipal Power Agency v. Northern States Power Co.*, the Commission stated that, in defining a changed request, it will not exalt form over substance.¹⁶

Section 211(c)(2) requires that a requesting utility cannot use a section 211 transmission order to replace electric energy sales made under a contract or a filed tariff.¹⁷ The Commission found in *City of Bedford* that the requesting party could buy power off-system under an ambiguous power requirements agreement when the transmitting utility ordered transmission service.¹⁸ The Commission also found that reduced purchase amounts would not require an impermissible change of billing under the power sales tariff.¹⁹ Previously, in ordering a hearing on contract interpretation, the FERC refused to decide in a section 211 proceeding whether the transmitting utility would have to credit the off-system power against its power bills to the requesting utility.²⁰ The Commission suggested that the requesting utility raise the crediting issue in a separate section 206 complaint.²¹

13. The Commission did come close, however, in *El Paso Elec. Co.*, 68 F.E.R.C. ¶ 61,182 (1994), when it chastised both the transmitting and requesting parties for "stonewalling," but granted further time for an information exchange.

14. 68 F.E.R.C. ¶ 61,169 (application for firm network service at all points of interconnection; Old Dominion's discretion limited to requests for firm network service primarily over single point of interconnection and secondarily over other points on an as-available basis).

15. See also *Tex-La*, 69 F.E.R.C. ¶ 61,269, at 30-31 (1994) (limiting ordered transmission to requested existing points of delivery and suppliers, but requiring a transmission contract provision that allows upgrade or termination of points of delivery).

16. 66 F.E.R.C. ¶ 61,323 (1994) (recently clarified MMPA request for a transmission-only contract deemed still to be good faith, because NSP responded with terms and conditions to which MMPA had earlier objected).

17. Transmission contracts can be replaced by section 211-ordered service. *Florida Mun. Power Agency*, 65 F.E.R.C. ¶ 61,125, at 61,614-15. Also, agreements to negotiate a transmission contract can be replaced by section 211-ordered service. *Tex-La*, 69 F.E.R.C. ¶ 61,269, at 20, 28 (rejecting reliance by both the requesting and transmitting utilities on their power supply agreement provision to negotiate transmission using the same pricing methodologies as before).

18. 66 F.E.R.C. ¶ 61,186 (interpreting contract), *reh'g denied*, 67 F.E.R.C. ¶ 61,063 (1994), 68 F.E.R.C. ¶ 61,003 (1994) (final order requiring transmission). The Commission also rejected the transmitting utility's claim for stranded investment costs on grounds: (i) that the power supply agreement did not provide for such charges; and, (ii) that the transmitting utility had no reasonable expectation of serving the requesting party's load for the duration of the contract. 68 F.E.R.C. ¶ 61,003 at 61,018-19.

19. 68 F.E.R.C. ¶ 61,003, at 61,020-21.

20. *City of Bedford*, 64 F.E.R.C. ¶ 61,381, at 63,640 (1993) (hearing order). Compare *Tex-La Elec. Coop.*, 64 F.E.R.C. ¶ 61,162 (1993) (denying section 211 jurisdiction in a dispute over a demand credit owed by a non-public utility for import of an off-system power resource).

21. Bedford later did so, and the FERC ordered the contracts modified to credit the off-system resources. *City of Bedford v. Appalachian Power Co.*, 68 F.E.R.C. ¶ 61,004 (1994).

Section 211(b) requires that transmission may not unreasonably impair the continued reliability of affected systems.²² The Commission has not yet made a finding of unreasonable impairment of reliability; and it has denied motions to reject applications on grounds of "unsubstantiated allegations" or "vague and speculative" claims of impairment.²³ Reliability may be encompassed within the issues of reasonable rates, terms, and conditions. In *El Paso Electric Co.*, for example, the requesting party argued that reliability was irrelevant and that the only matter at issue was the necessary modifications to the transmitting utility's system.²⁴ The Commission disagreed, however, stating that reliability involves all affected utilities in the region. Nevertheless, it preliminarily ordered provision of the transmission services, leaving the ultimate issue of reliability for its final order.²⁵

Five novel jurisdictional objections to section 211 applications were unsuccessful. First, in *Tex-La*, the transmitting utility argued that just as the FERC has no section 201(e) jurisdiction over local distribution facilities, it likewise has no section 211 jurisdiction to order transmission service that involves local distribution facilities (defined by the utility as interconnections at less than 60 kv). Defining transmission services as delivery to a lawful reseller, the Commission held that it had jurisdiction over transmission services *to* the facilities, even though it may not have jurisdiction *over* the facilities.²⁶

Second, also in *Tex-La*, the transmitting utility, located within the Electric Reliability Council of Texas and thus not subject to section 201(e) plenary jurisdiction, invoked Federal Power Act (FPA) Section 211(c)(2) to argue that the FERC had no jurisdiction to order the transmission service. The transmitting utility claimed that its transmission was conditioned upon payment of additional monies under its non-jurisdictional power supply agreement with the requesting party. Thus, the transmitting utility argued, the FERC had no jurisdiction to order transmission that would require FERC interpretation of a non-jurisdictional contract. The Commission, however, rejected the argument, interpreted the contract, and found the transmission to be unconditioned.²⁷

Third, in *El Paso Electric Co.*, the FERC rejected a claim that section 211 transmission was not valid for the purpose of effectuating a merger.²⁸

22. 16 U.S.C. § 824j(b) (1994).

23. *El Paso Elec. Co.*, 68 F.E.R.C. ¶ 61,182, at 61,938 n.38 ("Moreover, in future cases, we will not tolerate unsubstantiated allegations that reliability will be impaired, and expect that parties will provide support for their claims."); *Tex-La*, 67 F.E.R.C. ¶ 61,019, at 61,053-54 (rejecting claim that multiplicity of low voltage points of delivery under a remote telemetry arrangement would harm reliable control area operations, but allowing transmitting utility to propose terms and conditions necessary to assure reliability), *final order*, 69 F.E.R.C. ¶ 61,269 (1994) (reliability not an issue).

24. 68 F.E.R.C. ¶ 61,182, at 61,938, *clarified*, 68 F.E.R.C. ¶ 61,399 (1994).

25. *Id.*

26. *Tex-La*, 67 F.E.R.C. ¶ 61,019, at 61,054-56, *further discussed in Final Order*, 69 F.E.R.C. ¶ 61,269, at 62,026 (1994).

27. *Id.* at 61,054.

28. 68 F.E.R.C. ¶ 61,182, at 61,937.

Fourth, in *City of Bedford*, the FERC held that it need not first find that the contract for power to be wheeled is economically efficient or non-discriminatory.²⁹

Fifth, the Commission denied motions to reject transmission applications alleged to be "premature" because negotiations had not yet run their course.³⁰

Finally, the Commission explained that after it orders an otherwise non-jurisdictional utility to provide section 211 transmission, it retains section 211 jurisdiction.³¹ Employing procedures similar to sections 205 and 206, either the transmitting utility or the requesting party can file for changes in the transmission rate. If the requesting party wants changes in the service provided, then it must file a new section 211 application. In *Tex-La*, the Commission rejected a transmitting utility's attempt to cut off continued FERC jurisdiction via use of a contract clause barring any party from requesting modification to the transmission agreement.³²

C. *Mobile-Sierra Doctrine*

In a series of recent orders, the FERC has undertaken to limit the reach of the *Mobile-Sierra* doctrine.³³ In decisions involving Northeast Utilities Service Company,³⁴ Southern Company Services, Inc.,³⁵ Carolina Power & Light Company,³⁶ and Florida Power & Light Company,³⁷ the Commission stated that it would not follow the strict "public interest" test set forth in *Mobile-Sierra*, and *Papago*³⁸ for reviewing the terms and conditions of contracts. Rather, it said, it would apply a less stringent standard in circumstances where a contract either (i) affects buyers and consumers not parties to the contract; (ii) is between affiliates; (iii) is between affiliates and is not the product of arms-length bargaining; or, (iv) involves an exercise of market power by the seller.

Specifically, in *Carolina Power & Light Co.*, the Commission refused to accept a contract with a *Mobile-Sierra* clause because the clause allegedly did not allow the FERC to protect the interests of third parties. The parties were directed to add a replacement clause that would:

29. *City of Bedford*, 68 F.E.R.C. ¶ 61,003, at 61,019 (efficiency is satisfied by increased transmission service; discrimination claims should be brought in the docket where the off-system supplier seeks approval for the power supply agreement).

30. *Tex-La*, 67 F.E.R.C. ¶ 61,019, at 61,056-57; *Minnesota Mun. Power Agency*, 66 F.E.R.C. ¶ 61,060, at 61,189-90.

31. *Minnesota Mun. Power Agency v. Southern Minn. Mun. Power Agency*, 68 F.E.R.C. ¶ 61,060, at 61,208 (1994) (final order).

32. 69 F.E.R.C. ¶ 61,269, at 35 (1994).

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

34. *Northeast Utils. Serv. Co. v. FERC*, 993 F.2d 937 (1st Cir. 1993).

35. *Southern Co. Servs., Inc.*, 67 F.E.R.C. ¶ 61,080 (1994).

36. *Carolina Power & Light Co.*, 67 F.E.R.C. ¶ 61,074 (1994).

37. *Florida Power & Light Co.*, 67 F.E.R.C. ¶ 61,141 (1994).

38. *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950 (D.C. Cir. 1983), *cert. denied*, 467 U.S. 1247 (1984).

[P]ermit the Commission, either [*sua sponte*] or pursuant to a complaint by a non-party to the settlement . . . to investigate rates, terms and conditions under a "just and reasonable" standard at such times and under such circumstances as it deems appropriate.³⁹

In *Southern Co. Serv.*, the Commission explained its intent to limit the *Mobile-Sierra* doctrine to the maximum extent possible in order to use the just and reasonable standard of review. The FERC concluded that it is required to apply a public interest standard of review in only one "narrow circumstance," where: (i) the parties bind both themselves and the Commission to the public interest standard; and, (ii) the parties—or the Commission acting *sua sponte* on behalf of the parties—attempt(s) to depart from a contract previously accepted by the Commission under a just and reasonable standard of review.⁴⁰ The FERC declared that the public interest standard will not apply even in situations where it decides to act *sua sponte* on behalf of third parties to a contract who are not challenging it.⁴¹

Further, the Commission made explicit in *Southern*:

[W]e do not interpret the Commission in any circumstance to be bound, absent its consent, to a public interest standard of review when the Commission reviews an agreement initially.⁴²

In *Florida Power & Light Co.*, the Commission again emphasized its intent not to be bound to a public interest standard when initially reviewing a contract:

Parties to an agreement may not unilaterally preclude the Commission from fulfilling its statutory responsibility, under section 205 . . . to review the rates, terms, and conditions of an agreement to ensure that they are just and reasonable and not unduly discriminatory or preferential.⁴³

D. Filing Requirements

1. Final Order Concerning Prior Notice and Filing Requirements Under Part II of the Federal Power Act

Section 205 of the FPA requires that public utilities "file with the Commission . . . schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission" and prohibits changes "except after sixty days' notice to the Commission and to the public."⁴⁴ In *Central Maine Power Co.*,⁴⁵ the FERC expressed concern about compliance with these requirements, initiated a 60-day amnesty period, and warned utilities that failure to file jurisdictional agreements would result in substantial refund obligations.

39. *Carolina Power & Light Co.*, 67 F.E.R.C. ¶ 61,074, at 61,205.

40. *Southern Co. Servs.*, 67 F.E.R.C. ¶ 61,080, at 61,227.

41. *Id.* at 61,228.

42. *Southern Co. Servs.*, 67 F.E.R.C. ¶ 61,080, at 61,228 (citing *Northeast Utils. Serv. Co.*, 66 F.E.R.C. ¶ 61,332 (1994)).

43. *Florida Power & Light Co.*, 67 F.E.R.C. ¶ 61,141, at 61,396 (emphasis added).

44. 16 U.S.C. § 824d(c)-(d) (1994).

45. 56 F.E.R.C. ¶ 61,200, *reh'g denied*, 57 F.E.R.C. ¶ 61,083 (1991).

Confusion about the FERC's filing requirements caused the agency to provide two more amnesty periods: one for service agreements under umbrella tariffs,⁴⁶ and another for agreements relating to contributions in aid of construction (CIAC).⁴⁷ After convening a technical conference and reviewing numerous comments, the FERC issued its "Final Order Concerning Prior Notice and Filing Requirements Under Part II of the Federal Power Act,"⁴⁸ clarifying its filing requirements and establishing a final amnesty period.⁴⁹

In its July 30, 1993 order, the FERC established a general amnesty—through December 31, 1993—to allow utilities to submit previously unfiled wholesale power and transmission contracts without penalty. That order also revised the method by which the FERC will calculate refunds for late-filed jurisdictional agreements.

In the Appendix to the July 30 Order, the Commission provided general guidance with respect to seven categories of agreements: CIAC agreements; interconnection and service agreements between qualifying facilities and third party utilities (QF agreements); exchange agreements; pole attachment agreements; joint ownership agreements and operating and maintenance (O&M) agreements; borderline agreements; and, agreements involving a *de minimis* amount of money.

In addition to clarifying the jurisdictional status of these types of agreements, the July 30 Order stressed:

To the extent a utility remains uncertain, even after consulting this order and the appendix, as to its obligation to file rates and charges for a particular transaction or type of transaction, it should assume the initiative to seek a specific ruling.⁵⁰

The Commission suggested that, in such circumstances, the utility should either (1) file the agreement and simultaneously ask the FERC to disclaim jurisdiction; (2) file a petition for a declaratory order; or, (3) request a written interpretation from the Office of the General Counsel.⁵¹

a. CIAC Agreements

Utilities must file agreements which provide for contributions in aid of construction for all jurisdictional facilities constructed after August 2, 1991.⁵² Any such contract must be filed regardless of whether it calls for periodic or lump-sum payments, because FERC's jurisdiction:

[D]epends on whether the contract contains a rate or charge for or in connection with the transmission or sale of electric energy in interstate commerce, or

46. *New England Power Co.*, 61 F.E.R.C. ¶ 61,015 (1992).

47. *Florida Power Corp.*, 61 F.E.R.C. ¶ 61,063 (1992).

48. 64 F.E.R.C. ¶ 61,139, *order on reh'g and clarification*, 65 F.E.R.C. ¶ 61,081 (1993).

49. For additional background and discussion, see Joshua Rokach, *FERC's Jurisdiction Under Section 205 of the Federal Power Act*, 15 Energy L.J. 83 (1994).

50. 64 F.E.R.C. ¶ 61,139, at 61,977-78.

51. *Id.*

52. 64 F.E.R.C. ¶ 61,139 at 61,990.

whether the contract affects or relates to such rates or service . . . not . . . on the timing of payment under the contract.⁵³

Any CIAC agreement under which a customer makes a payment related to the construction of generating facilities, in place of a per unit charge for wholesale service, must be filed.⁵⁴

Although CIAC agreements for construction completed before August 2, 1991, need not be filed, a utility must file rates for any jurisdictional transmission or wholesale power sales using such facilities.⁵⁵ The FERC considers payments made pursuant to CIAC agreements when it determines whether the rate for any jurisdictional service is just and reasonable.

b. QF Agreements

In *Western Massachusetts Electric Co.*,⁵⁶ the Commission established that utilities must file agreements providing for the transmission of power from a QF to the purchasing utility even though state authorities have exclusive jurisdiction over the QF's direct interconnection.⁵⁷

c. Exchange Agreements

A utility must file its exchange agreements or any new agreements under which it assigns back its entitlement to power or capacity.⁵⁸ Exchange agreements and amendments to exchanges of the actual electric energy or entitlement to production of generating plants must also be filed unless both sides of the exchange occur outside of the United States.

d. Pole Attachment Agreements

Agreements that involve utilities leasing space on transmission poles need not be filed because the associated charges are "not for or in connection with the transmission or sale for resale of electric energy in interstate commerce."⁵⁹

e. Joint Ownership Agreements and O&M Agreements

Agreements for the joint ownership or operation of *transmission* facilities must be filed. However, as agreements concerning joint ownership or operation of *generating* plants are not jurisdictional, they need not be filed unless they (i) contain provisions affecting or relating to wholesale sales of

53. *Id.*

54. *Id.*

55. *Id.*

56. 59 F.E.R.C. ¶ 61,091, *reh'g denied*, 61 F.E.R.C. ¶ 61,182 (1992).

57. 64 F.E.R.C. ¶ 61,139, at 61,991 (citing *Western Massachusetts Elec. Co.*, 59 F.E.R.C. ¶ 61,091 (1992)).

58. *Id.* at 61,992.

59. *Id.* at 61,986.

energy in interstate commerce; or, (ii) include transmission facilities such as step-up transformers.⁶⁰

An entity that receives payments or performs services pursuant to an O&M agreement must file the agreement if: (i) it is a public utility; and, (ii) the agreement “contain[s] rates or charges for or in connection with transmission or sales for resale in interstate commerce,” or affects or relates to jurisdictional rates or services.⁶¹

f. Borderline Agreements

A borderline agreement is an arrangement:

[U]nder which one utility (for convenience) serves the retail customers of a neighboring utility along the electric franchise areas common to both. The utility delivering the power, in turn, bills the nominal seller.⁶² The FERC considers borderline agreements to be “sale[s] for resale” which must be filed.⁶³

g. *De Minimis* Contracts

While the Commission continues to follow the “rule of reason” set forth in *Town of Easton v. Delmarva Power and Light Co.*,⁶⁴ it nevertheless refused to create a generic exception to its filing requirements for *de minimis* contracts. The FERC will determine whether to decline jurisdiction over *de minimis* contracts on a case-by-case basis.

2. Order on Rehearing

On rehearing, the FERC clarified its July 30 Order in four areas.⁶⁵ *First*, the FERC clarified that, when the price in a service agreement is stated as a ceiling rate, transactions at negotiated prices below that ceiling rate may be carried out without additional FERC filings. *Second*, the FERC clarified that agreements providing for a utility to reimburse another utility for transmission losses in kind—through the return of energy rather than through a dollar payment—are jurisdictional and must be filed. *Third*, the Commission explained that, if a jurisdictional utility is a party to an exchange agreement with a non-jurisdictional utility, the jurisdictional utility must not only file the exchange agreement, but must also

60. 64 F.E.R.C. ¶ 61,139, at 61,993 (citing *Mississippi Indus. v. FERC*, 808 F.2d 1525 n.74 (D.C. Cir. 1987)).

61. *Id.* The operator of a jurisdictional facility is a public utility if it controls and has decision-making authority over the facility. If the operator acts as an agent of another party, or requires permission for all non-routine, non-emergency operational and maintenance actions, it is not a public utility. The FERC has also disclaimed jurisdiction over owners who are merely passive investors. *Id.* at 61,994 (citations omitted).

62. *Id.* at 61,994.

63. *Id.*

64. 24 F.E.R.C. ¶ 61,251 (1983).

65. *Prior Notice and Filing Requirements Under Part II of the Federal Power Act, Order Granting Motion for Intervention and Granting in Part and Denying in Part Motions for Clarification and Rehearing*, 65 F.E.R.C. ¶ 61,081 (1993).

file an amendment to that agreement should there be a change in the amount of power purchased. *Finally*, the FERC concluded that contracts need not be filed if: (i) they provide only for a utility to study the impact of requested transmission service on its system; (ii) the study is performed at the expense of the requesting party; and, (iii) the requesting party does not file a complaint.⁶⁶

3. FERC's Review of Amnesty Filings

Utilities filed numerous agreements with the Commission under the July 30 amnesty. In acting on these filings, the FERC provided further guidance on the types of agreements that need to be filed. For example, in *Midwest Power Systems, Inc.*,⁶⁷ the Iowa Utilities Board intervened to contest FERC jurisdiction, claiming that "the [joint ownership] agreement concerns predominantly generation matters traditionally within [the state's] regulatory domain and, accordingly, that [the FERC] should ignore the 'minor' transmission aspects of the joint ownership arrangement."⁶⁸ The FERC concluded that the agreement had to be filed. The FERC explained:

If the agreement can be separated into two agreements (one covering jurisdictional matters and one covering nonjurisdictional matters), the parties to the agreement can do so and then [the utility] can file the agreement covering only jurisdictional matters. . . .⁶⁹

The Commission also required utilities to file day-to-day scheduling procedures for interruptible transmission services that implement filed rate schedules.⁷⁰ Likewise, the FERC required a utility to file its amendments to a power pool agreement, rejecting the argument that the filing requirement should be waived under the "rule of reason."⁷¹ The FERC did not, however, require filing of a communications agreement among the power pool members.⁷²

The FERC also held that service agreements involving export sales to a foreign entity need not be filed.⁷³ In *Long Island Lighting Co.*,⁷⁴ the

66. *Id.* at 61,505.

67. 69 F.E.R.C. ¶ 61,025 (1994).

68. *Id.* at 61,105.

69. *Id.*

70. See *Southern Cal. Edison Co.*, 68 F.E.R.C. ¶ 61,266, at 62,168 (1994). The FERC required filing because the scheduling provisions at issue were "critical terms and conditions of Edison's transmission service, and therefore, significantly affect jurisdictional service; are susceptible to specification . . . and are not so understood as to render their recitation superfluous."

71. *Public Ser. Co.*, 67 F.E.R.C. ¶ 61,371 (1994). The utility asserted that, because the amendments dealt with day-to-day operations, they need not be filed under the "rule of reason." The FERC responded that the utility had to explain why the agreements fell outside the FERC's jurisdiction or fell within the "rule of reason." The Commission stated further that the "rule of reason applies when [the Commission] has jurisdiction over the particular contract or practice, but nevertheless . . . allow[s] utilities to forgo filing. . . ." *Id.* at 62,267. The FERC was not persuaded to disclaim jurisdiction merely because the amendments governed day-to-day operations.

72. *Id.* at 62,268.

73. See *Arizona Pub. Serv. Co.*, 2 F.E.R.C. ¶ 61,080 (1978).

74. 68 F.E.R.C. ¶ 61,345, denying reh'g of 66 F.E.R.C. ¶ 61,268 (1994).

FERC disclaimed jurisdiction over an underwater cable agreement and related O&M agreements, ruling that the utility involved is neither an owner nor operator of the cable.⁷⁵ Finally, in *Ogden Martin Systems*,⁷⁶ the FERC granted a request for declaratory order, finding that “the sale of steam is not subject to our jurisdiction under the Federal Power Act.”⁷⁷

E. Mergers

1. El Paso—Central and South West Merger

The FERC ordered a hearing on the proposed merger of El Paso Electric into Central and South West due to concern about the merger’s impact on costs and rate levels and its potential anti-competitive effects.⁷⁸ The Commission noted that it no longer believes that “increases in transmission market power as a result of a merger can be adequately mitigated without an offer of comparable transmission services.”⁷⁹ The FERC, however, chose not to apply its comparability requirement to transmission services within the Electric Reliability Council of Texas.

After the court of appeals’ decision in *Cajun Electric Power Cooperative v. FERC (Cajun)*,⁸⁰ the FERC required proposed stranded cost provisions to be deleted from the proposed transmission tariffs. In *Cajun*, the D.C. Circuit questioned whether Entergy’s open-access transmission tariff, which contained a stranded cost recovery provision, adequately mitigated market power.

2. Approval of PSI–CG&E Proposed Merger

The FERC withdrew its prior, conditional approval of PSI Energy’s merger with Cincinnati Gas & Electric citing deep concern about the state of the record on the merger’s impact on effective regulation.⁸¹ Subsequently, the merger candidates filed a number of settlement agreements and unilateral offers of settlement, including an Operating Agreement;

75. 68 F.E.R.C. ¶ 61,345, at 62,390-91. See also *Long Island Lighting Co.*, 67 F.E.R.C. ¶ 61,361 (1994). The FERC found that the O&M agreements were not within its jurisdiction because LILCO acted “merely as the agent of another party wielding authority to make main operational decisions, [and was] not ‘operating’ the facility . . . accordingly, it need not file the O&M agreement, even if it is a public utility.” 67 F.E.R.C. ¶ 61,361, at 62,254 (citing 64 F.E.R.C. at ¶ 61,139, 61,993-94). See also *Puget Sound Power & Light Co.*, 64 F.E.R.C. ¶ 61,335 (1993) (disclaiming jurisdiction where the utility had little discretion to perform the work under the agreement).

76. 66 F.E.R.C. ¶ 61,152 (1994).

77. *Id.* at 61,294 (citing 64 F.E.R.C. ¶ 61,139, at 61,985-89, *order on clarification*, 65 F.E.R.C. ¶ 61,081 (1993)).

78. *El Paso Elec. Co.*, 68 F.E.R.C. ¶ 61,181 (1994).

79. *Id.* at 61,914. In *American Elec. Power Serv. Corp.*, 67 F.E.R.C. ¶ 61,168, at 61,490 (1994), the Commission announced a new standard of comparability to be applied in determining whether transmission tariffs are unduly discriminatory or anticompetitive:

[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.

67 F.E.R.C. ¶ 61,168, at 61,490.

80. 28 F.3d 173 (D.C. Cir. 1994).

81. *Cincinnati Gas & Elec. Co.*, 66 F.E.R.C. ¶ 61,028 (1994).

agreed to remove the issue of stranded investment from the proceeding; and amended their *pro forma* tariffs to provide transmission service comparability. The FERC approved the merger⁸² without addressing American Electric Power's argument that the merged companies' use of its transmission system (as a result of loop flow) results in a "permanent appropriation." It concluded instead that the issue should first be addressed to an industry forum before the FERC is asked to consider any request for compensation.

3. Mergers of Holding Companies

Despite its lack of jurisdiction where two utility holding companies merge, the FERC announced in *Illinois Power Co.*,⁸³ a rebuttable presumption that any such merger is accompanied by a simultaneous indirect merger of the public utility subsidiaries' jurisdictional facilities. The presumption may be rebutted by a showing that the public utility subsidiaries will still effectively compete with each other after the holding companies' merger.

F. Regulation of Power Marketers

Power marketers purchase electricity and resell it at wholesale at negotiated or market-based rates. Marketers also may engage in a variety of related non-utility, non-jurisdictional activities, such as brokering power transactions and providing risk-management services. Power marketers are regulated as public utilities by the FERC under the FPA.⁸⁴ The FERC's basic criteria for granting blanket approval to transact business at negotiated—as opposed to cost-based—rates, and the regulatory waivers and authorizations usually granted with such approval, have remained unchanged since 1989.⁸⁵

82. *Cincinnati Gas & Elec. Co. and PSI Energy, Inc.*, 69 F.E.R.C. ¶ 61,005 (1994).

83. 67 F.E.R.C. ¶ 61,136 (1994).

84. The FERC's jurisdiction over marketers is based on their wholesale contracts being "facilities" under FPA Section 201(e), 16 U.S.C. § 824(e) (1988). *Citizens Energy Corp.*, 35 F.E.R.C. ¶ 61,198, at 61,452 (1986) (citing *Hartford Elec. Light Co. v. FPC*, 131 F.2d 953 (1942), *cert. denied*, 319 U.S. 741 (1943)).

Importantly, however, the staff of the Securities and Exchange Commission apparently does not regard a power marketer's contracts as "facilities" for purposes of the Public Utility Holding Company Act of 1935 (PUHCA), and would not recommend that a marketer be treated as an "electric utility company" under that statute. *Enron Power Mktg., Inc.*, SEC No-Action Letter, 1994 SEC No-Act. LEXIS 42, *6 (Jan. 5, 1994); *CRSS Power Mktg., Inc.*, SEC No-Action Letter, 1994 SEC No-Act. LEXIS 431 (Mar. 31, 1994); *Electric Clearinghouse, Inc.*, SEC No-Action Letter, 1994 SEC No-Act. LEXIS 452 (April 13, 1994). The FERC has denied a power marketer exempt wholesale generator (EWG) status, which would have provided an exemption from PUHCA, for similar reasons. *Louis Dreyfus Elec. Power, Inc.*, 62 F.E.R.C. ¶ 61,234 (1993).

85. *Citizens Power & Light Co.*, 48 F.E.R.C. ¶ 61,210 (1989). Prior decisions established precedent for granting authorization to sell at negotiated rates and waiving certain reporting obligations only in the absence of market power. *E.g., Ocean State Power*, 44 F.E.R.C. ¶ 61,261 (1988); *Cliffs Elec. Serv. Co.*, 32 F.E.R.C. ¶ 61,372 (1985).

1. Non-Affiliated Power Marketers

a. Standard Requirements

Power marketers that are not affiliated with a vertically integrated electric utility have been allowed to sell at negotiated rates and have been granted waivers from various regulatory obligations that apply to traditional utilities, upon showing (1) lack of ownership of generation or transmission facilities or inputs to electric power production; (2) lack of affiliation with any entity that owns generation (other than generation committed under long-term contracts or previously determined to convey no market power) or transmission facilities or other inputs to electric power production; (3) lack of affiliation with any entity that has a franchised service area; and, (4) lack of business arrangements (including sales of accounts receivable) involving the marketer or any affiliate and the entities which buy power from, or sell power to, the marketer or transmit power for the marketer. These requirements are intended to eliminate any concern that the marketer could influence the price at which it buys or sells electricity.⁸⁶ A marketer must report any change in its status with respect to these criteria.

To enable the FERC to monitor the reasonableness of a marketer's charges and its ability to exercise market power, each marketer is required, thirty days after the end of each calendar quarter, to file reports itemizing the quantities and prices, contract duration, receipt and delivery points, and nature of service (firm or non-firm) for each of its purchases and sales during the prior quarter. Like the FERC's criteria for approving market-based rates, the waivers and authorizations typically granted to power marketers are similar to those the agency has applied to independent power producers.⁸⁷

Consistent with *Central Hudson Gas & Electric Corp.*,⁸⁸ and "Prior Notice and Filing Requirements Under Part II of the Federal Power Act,"⁸⁹ the Commission will waive its 60-day prior notice requirement (i) for uncontested new service filings made at least one day prior to the commencement of service; and, (ii) for service agreements under tariffs already on file, if the service agreements are filed within thirty days after service

86. A marketer's rate schedule must include a prohibition on the sale of electricity to any entity owned or controlled by the marketer, as well as to any entity under common control with, or controlling, the marketer. *E.g., Acme Power Mktg., Inc.*, Letter Order (Oct. 18, 1994).

87. The Commission has granted: waiver of parts 41, 50, 101, 104, and 141 of its regulations (accounting and related requirements); limited waiver of parts 45 and 46 (interlocking directorships and officers); waiver of most of subparts B and C of part 35 (content of filings, cost support for initial and changed rates, notices of cancellation and succession, and various other requirements); and blanket approval under part 34 of all future issuances of securities and assumptions of liability (subject to public intervention or protest). The filing fees applicable to public utilities have not been waived.

88. 60 F.E.R.C. ¶ 61,106 (1992).

89. 64 F.E.R.C. ¶ 61,139 (1993).

commences.⁹⁰ Upon a showing of good cause, the FERC will also waive the notice requirements pursuant to FPA Section 205(d)⁹¹ and FPA Section 35.11 of the Commission's Regulations⁹² to permit a marketer's rate schedule to become effective sixty days after the date of its initial good faith tender.⁹³

b. Affiliation with Natural Gas Companies

A standard condition of approval for marketers affiliated with entities that own or control intrastate gas transportation and storage facilities, or otherwise market fuel supplies, is that, should any affiliate deny, delay, or require unreasonable terms, conditions, or rates for fuel-related services to a potential electric competitor, the competitor may file a complaint; if justified, such a complaint could lead to the suspension of the marketer's authority to sell electricity at market-based rates.⁹⁴ Affiliation with open-access interstate natural gas pipelines is presumed not to raise similar concerns.⁹⁵

c. Affiliation with QFs or IPPs

Affiliation with an entity that owns generating capacity, such as an owner of a use QF or an independent power producer (IPP), is not assumed to confer market power if: (i) the entire output of the QF or IPP project is fully committed under long-term contracts; or, (ii) the affiliate itself is found to lack market power. For example, in approving a market-based rate schedule for Enron Power Marketing, Inc., the Commission addressed a situation in which the power marketer was part of a diversified energy enterprise, including companies with interests in four QFs and one IPP project.⁹⁶ Enron itself owned no generating facilities, and none of its affiliates had a franchised service territory. Each of the QFs' entire output was committed under long-term contracts. The IPP, Milford Power Limited Partnership, had uncommitted capacity but had previously been authorized to sell to any buyer at market-based rates, based on its own

90. *E.g.*, *R.J. Dahnke & Ass's*, Letter Order (Aug. 10, 1994); *Eclipse Energy, Inc.*, Letter Order (June 15, 1994); *AES Power Inc.*, Letter Order (Apr. 14, 1994).

91. 16 U.S.C. § 824d(d) (1988).

92. 18 C.F.R. § 35.11 (1994).

93. *E.g.*, *Morgan Stanley Capital Group Inc.*, 69 F.E.R.C. ¶ 61,175 (1994) [hereinafter MS Capital].

94. *E.g.*, *CNG Power Serv. Corp.*, Letter Order (Oct. 25, 1994); *Coastal Elec. Serv. Co.*, Letter Order (Sept. 29, 1994).

95. *Enron Power Mktg., Inc.*, 65 F.E.R.C. ¶ 61,305 at 62,405 (1993).

96. *Id.*

demonstrated lack of market power.⁹⁷ The FERC directed Enron to report any new generating projects in which it or its affiliates acquire an interest.

d. Affiliation with Financial Services Companies

Morgan Stanley Capital Group, Inc. (MS Capital), an affiliate of Morgan Stanley Group, Inc., is the first affiliate of an investment banking house to win approval as a power marketer.⁹⁸ The Commission held that ownership or control of generation would not be ascribed to the marketer because of transitory holdings of electric utility securities by its affiliates in connection with investment or merchant banking, market-making, or asset management activities.⁹⁹ The FERC also allowed MS Capital the option to file a new analysis of its market power every three years in lieu of continually reporting changes in its affiliates' investments in generation or other entry barriers.¹⁰⁰ MS Capital was refused blanket authority to purchase power from or sell power to affiliates that do not have franchised retail service areas, such as QFs or exempt wholesale generators (EWGs). The Commission reiterated its ban on affiliate transactions at market-based rates, but allowed MS Capital to file for approval of a specific affiliate transaction.

e. Reporting Business Arrangements

In *Enron*¹⁰¹ and *MS Capital*,¹⁰² the Commission clarified the types of business arrangements between a marketer (or its affiliates) and the marketer's customers that must be reported to or approved by the FERC. In its December 1993 order approving Enron's market-based rates, the Commission distinguished between a marketer's assignment of a power sales contract and the sale of accounts receivable. The assignment of a power sales contract (with a value exceeding \$50,000), which is a jurisdictional "facility" for a power marketer, must be approved by the Commission

97. *Milford Power Ltd.*, 64 F.E.R.C. ¶ 61,306 (1993) (Letter Order). As Milford Power's only transmission facilities connected it to one local utility, it was found to lack transmission market power. *Id.* at 63,326.

98. *MS Capital*, 69 F.E.R.C. ¶ 61,175 (1994).

99. MS Capital asked the FERC to adopt a 10% voting interest threshold for affiliation. (The Commission has not established a bright line test for affiliation.) The FERC responded that, until further guidance is provided, MS Capital should determine affiliation by applying the definition set forth in 18 C.F.R. pt. 101, Definitions, at 5, which states that "associated (affiliated) companies means companies or persons that directly, or indirectly through one or more intermediaries, control, or are controlled by, or are under common control with" the utility. The FERC also noted, however, that FPA Section 214, as amended by the Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (codified at 42 U.S.C.A. §§ 13,201-13,556 (West Supp. 1995)) [hereinafter EPAct] requires the term "affiliate" to be determined under a 5% standard, as it is under the PUHCA. *Id.* at 61,693.

100. *Id.* at 61,695 n.7 (citing *Louisville Gas & Elec. Co.*, 62 F.E.R.C. ¶ 61,016, at 61,148 (1993)).

101. 65 F.E.R.C. ¶ 61,305 (1993).

102. 69 F.E.R.C. ¶ 61,175 (1994).

under FPA Section 203.¹⁰³ In contrast, the sale of an account receivable, which would not effect a change in the contractual obligation or facilities used for a jurisdictional transaction, would *not* require approval under section 203, but *would* have to be reported in compliance with a marketer's authorization to sell electricity at market-based rates.

In its request for rehearing of the December 1993 decision, Enron asked that its obligation to report business and financial arrangements be limited to generating projects undertaken by the marketer or its affiliates, and specifically to generating projects with uncommitted power. On rehearing, the FERC denied Enron's request, explaining that its requirements are purposefully broad to enable it to detect a marketer's ability (i) to engage in self- or reciprocal dealing; (ii) to erect barriers to entry; or, (iii) generally to achieve market power.¹⁰⁴ The Commission clarified, however, that its informational requirement applies only to Enron's affiliates located in the United States, Puerto Rico, Canada, and Mexico. While acknowledging the difficulties that its decision poses for marketers in a large diversified corporate family, the Commission nevertheless concluded that this reporting requirement could not be relaxed; it agreed, however, to entertain a request for waiver or modification of any aspect of the informational requirement at some later date.¹⁰⁵

A few months after the *Enron* decision, MS Capital sought a full waiver of its obligation to report business and financial arrangements between itself or any affiliate and entities that buy power from or sell power to it.¹⁰⁶ The FERC denied the request, but announced that it would review its reporting requirements in light of changes in the industry and the varied affiliations of power marketers.¹⁰⁷ Finally, MS Capital asked the Commission to relieve it of the obligation to report its or its affiliates' financial transactions, such as swaps or futures, that do not result in the delivery of electricity. The FERC agreed, but stated that MS Capital's quarterly reporting requirements would be addressed in a subsequent order.¹⁰⁸

103. 65 F.E.R.C. ¶ 61,305 (1993).

104. *Enron Power Mktg., Inc.*, 66 F.E.R.C. ¶ 61,244, at 61,597-58 (1994). With respect to uncommitted power resources, the Commission noted that committed power becomes uncommitted when the contract expires. The FERC required that all interests in generating facilities be reported when acquired, whether or not the power is committed under a long-term contract. Only fully executed arrangements need be reported. *Id.* at 61,599.

105. *Id.* at 61,598.

106. 69 F.E.R.C. ¶ 61,175, at 61,694. MS Capital argued that its affiliates are involved in numerous and disparate investments, which are unlikely to result in control of generation or transmission facilities, but which would be impractical to report and could violate those affiliates' confidentiality obligations to their clients. *Id.*

107. *Id.* at 61,695.

108. *Id.* at 61,696.

f. Confidentiality and Other Reporting Requirements

The Commission denied Enron's request that the information in its quarterly reports be accorded confidential treatment.¹⁰⁹ Enron had also argued in its rehearing request that filing the maximum rate provided for in an agreement with a customer should be sufficient, since, if that rate does not raise questions regarding market power or reasonableness, a lower actual rate should certainly not raise such questions. On rehearing, the FERC rejected Enron's argument, explaining that, under future circumstances, an actual rate could reflect market power or otherwise be unreasonable even if the maximum contract rates were not unreasonable at the time the contract had been executed.¹¹⁰

2. Affiliated Marketers

In August 1994, the FERC approved the applications of three power marketers affiliated with utilities that own generation and transmission systems and have retail service areas.¹¹¹ Approval of market-based rates was conditioned upon (1) the filing of a comparable-service transmission tariff by each affiliate owning transmission facilities; (2) a prohibition on purchases and sales between the marketer and an affiliate, except with Commission approval of a specific transaction; and, (3) the establishment of procedures to prevent the marketer from benefitting from its affiliated utility's market information.

a. Heartland Energy Services

Heartland Energy Services is a wholly-owned subsidiary of WPL Holdings, Inc., which also owns Wisconsin Power & Light Company (WP&L), a traditional vertically integrated electric utility.¹¹² Heartland asserted its compliance with the standard criteria for lack of market power in generation, transmission, retail, and generation input markets, and agreed that it would not engage in sales or purchases of electric energy with

109. *Enron Power Mktg., Inc.*, 65 F.E.R.C. ¶ 61,305, at 62,406 (1993) (citing *National Elec. Assoc. Ltd.*, 50 F.E.R.C. ¶ 61,378 (1990)).

110. 66 F.E.R.C. ¶ 61,244, at 61,599 (1994). The FERC has also denied requests for confidentiality or other protection for commercially sensitive information by power marketers affiliated with vertically integrated utilities: *Heartland Energy Servs., Inc.*, 68 F.E.R.C. ¶ 61,223 (1994) (request for confidential treatment denied); *LG&E Power Marketing Inc.*, 68 F.E.R.C. ¶ 61,247, at 62,124-25 (1994) (request to delay reporting a transaction for six months dismissed as unworkable).

111. Heartland Energy Services, Inc. (affiliated with Wisconsin Power & Light Co.); InterCoast Power Marketing Co. (affiliated with Iowa-Illinois Gas & Electric Co.); and LG&E Power Marketing, Inc. (affiliated with Louisville Gas & Electric Co.). Market-based rates also have been approved for Cenergy, an affiliate of Northern States Power Company, subject to refund pending investigation of the utility's comparable-service transmission tariff.

112. *Heartland Energy Servs., Inc.*, 68 F.E.R.C. ¶ 61,223 (1994).

its affiliate, WP&L.¹¹³ Heartland sought the same waivers and authorizations that the FERC had granted to other power marketers.

i. Lack of Generation Market Power

The Commission required Heartland to demonstrate that neither it nor its affiliates could dominate the short-run market for uncommitted capacity and energy from existing facilities by (1) showing that the entire output of an affiliate's generation facilities is committed under long-term contract with a non-affiliate; (2) showing that the affiliate already had authority to sell at market rates; or, (3) submitting a market analysis showing that its affiliate could not exercise generation dominance in the relevant markets.¹¹⁴

Heartland relied on the third alternative. The relevant geographic markets for generation were defined as each of the potential customers directly interconnected to Heartland's affiliates (first tier markets).¹¹⁵ Heartland's analysis showed that in the first-tier markets, WP&L's market share for uncommitted capacity ranged from 3% to 9% percent and its installed capacity share in each market ranged from 3% to 6% percent with an open-access transmission tariff in place. The FERC found that these shares were low enough to show that WP&L could not exercise market power in those markets and, therefore, lacked dominance in second- or third-tier markets as well.¹¹⁶

ii. Lack of Transmission Market Power

Each transmission-owning affiliate of a marketer must file an open-access tariff offering comparable services to mitigate its market power in transmission. The marketer is required to buy transmission service under the same tariff. With some modifications, WP&L's transmission tariff was found to meet the requirements, and thus Heartland's market-based rates were approved, subject to refund, as of the day WP&L filed its tariff.

iii. Lack of Market Power to Raise Other Barriers to Entry

The Commission assessed the degree of control held by Heartland's affiliates over various inputs to generation, such as ownership of building

113. Enron Power Marketing, Inc., an intervenor, argued that structural changes in the industry were required before a utility affiliate should be authorized to sell at market-based rates. *Id.* at 62,057. The Commission found that the conditions it imposed on Heartland when approving its rate schedule would be sufficient to protect competitors. *Id.* at 62,066.

114. *Id.* at 62,063. The Commission has determined that there are no concerns about generation dominance for a facility that has not yet been built (*i.e.*, new capacity). *Kansas City Power & Light Co.*, 67 F.E.R.C. ¶ 61,183, at 61,557 (1994) (rehearing pending).

115. 68 F.E.R.C. ¶ 61,223, at 62,061.

116. *Id.* at 62,063. The Commission's rule of thumb is that a market share of 20% or more is assumed to reflect market power. *See id.* at 62,063 n.12.

sites, affiliations with owners of interstate natural gas pipelines, and engineering/construction firms. No impermissible barriers to entry were found, although Heartland's affiliate owns local gas distribution facilities and sells and transports natural gas within a franchised service territory. However, if the FERC receives complaints that WP&L has refused gas services to anyone or offered services on discriminatory terms, Heartland's market-based rate authorization could be rescinded.¹¹⁷

iv. Absence of Affiliate Abuse

The Commission's conditions on approval are intended to prevent affiliate abuse, including preemption of transactions by an affiliate for the benefit of the marketer, preferential access to an affiliate's services, and preferential power sales between an affiliate and the marketer.¹¹⁸ To guard against such abuses, the Commission required Heartland (1) to notify the FERC of any transactions between it and entities with a business relationship with its affiliate in the United States, Puerto Rico, Canada, or Mexico; (2) to show that it pays no less than market value for all services it receives from the utility; and, (3) to agree not to sell power to or buy power from its utility affiliate without a separate filing requesting FERC approval of a specific transaction.¹¹⁹ A marketer also must show that procedures are in place to preclude the sharing of its affiliated utility's information—particularly market information. The Commission found that Heartland met the necessary requirements, and that procedures already required by the Wisconsin Public Service Commission to regulate cost allocation between it and WP&L would further guard against abusive self-dealing.¹²⁰

The Commission approved Heartland's market-based rate application to become effective as of the date WP&L submits an open-access transmission tariff reflecting comparable service terms and conditions. The FERC also granted Heartland the standard regulatory waivers.¹²¹ The Commission applied the principles announced in *Heartland* to the applications filed by two other affiliated marketers, InterCoast Power Marketing Company and LG&E Power Marketing Inc.¹²²

117. *Id.* at 62,064.

118. These prohibitions on affiliate transactions, particularly the ban on sales to or purchases from the utility, are based on decisions regarding IPPs affiliated with utilities. *Id.* at 62,062-63 (citing *TECO Power Servs. Corp.*, 52 F.E.R.C. ¶ 61,191, at 61,698, *reh'g denied*, 53 F.E.R.C. ¶ 61,202 (1990), *Terra Comfort Corp.*, 52 F.E.R.C. ¶ 61,191, *order on reh'g*, 53 F.E.R.C. ¶ 61,202 (1990)).

119. 68 F.E.R.C. ¶ 61,233, at 62,062, 62,063.

120. *Id.* at 62,064-65.

121. While the Commission held that it would not waive prior notice to permit an effective date of the rate schedule prior to its decision, it did grant a limited waiver to allow the effective date to coincide with the filing of WP&L's comparable services transmission tariff. *Id.* at 62,065.

122. *InterCoast Power Mktg. Co.*, 68 F.E.R.C. ¶ 61,248 (1994); *LG&E Power Mktg. Inc.*, 68 F.E.R.C. ¶ 61,247 (1994).

b. InterCoast Power Marketing Company

Unlike WP&L, InterCoast's affiliated utility, Iowa-Illinois Gas & Electric Company (Iowa-Illinois), did not have an open-access transmission tariff in place. Accordingly, the FERC rejected InterCoast's proposal to sell only to third-tier or more remote utilities as an unacceptable alternative for mitigating its utility affiliate's transmission market power. The Commission stated that it would be (i) too difficult to determine "regions in which [the applicant's] competitors would not need comparable access to Iowa-Illinois' transmission system;"¹²³ and, (ii) too costly to continually reevaluate market power as regional market opportunities changed. InterCoast's rate schedule was approved effective as of the date Iowa-Illinois files a comparable-service transmission tariff.

The Commission found no generation market dominance. Iowa-Illinois' share of uncommitted capacity in the first-tier market ranged from only 4% to 17%, and its installed capacity share ranged from 4% to 11%. InterCoast also stated that it would not sell power to its utility affiliates or to any utilities (directly interconnected to Iowa-Illinois's transmission system). The FERC concluded that this proposal, in conjunction with applicable Illinois law for monitoring the cost allocation between InterCoast and Iowa-Illinois, was sufficient to safeguard against affiliate abuse.¹²⁴

c. LG&E Power Marketing Inc.

The Commission found that LG&E Power Marketing Inc. (LG&E), an affiliate of Louisville Gas & Electric Company (Louisville), met all of the *Heartland* criteria, but approval was conditioned on Louisville filing an acceptable comparable services transmission tariff.¹²⁵ The FERC refused to accept Louisville's "commitment" to provide comparable transmission services in the absence of revisions to its transmission tariff properly defining and pricing those services.¹²⁶

Louisville could delay "good faith" negotiations for comparable services to favor its affiliate, LG&E Marketing. Such a result would be anticompetitive. Moreover, without a defined comparability tariff on file, Louisville could unduly discriminate in favor of its affiliated power marketer by "negotiating" more favorable rates, terms and conditions with LG&E Marketing than it negotiates with non-affiliate suppliers for the same or comparable services.¹²⁷

While LG&E itself owns an interest in a QF, is affiliated with a public utility, and has other affiliates with interests in ten different QF projects, the Commission found no market power in generation. The FERC had

123. 68 F.E.R.C. ¶ 61,248, at 62,132.

124. *Id.* at 62,131-32. The Commission found that Iowa-Illinois's involvement in oil and gas ventures did not constitute a barrier to entry sufficient to defeat InterCoast's market rate authorization. *Id.* at 62,132-33.

125. 68 F.E.R.C. ¶ 61,247, at 62,118.

126. *Id.* at 62,120.

127. *Id.* at 62,122.

previously found that Louisville lacked generation dominance and had authorized the utility to sell electricity at market-based rates; the output of all of the QFs was fully committed under long-term contracts.¹²⁸

The Commission rejected LG&E's argument that it was unnecessary to establish specific procedures for restricting its access to Louisville's marketing information, even if Louisville also would offer such information to non-affiliated power marketers and brokers. Louisville was ordered to adopt and submit to the FERC a statement of corporate policy that prohibits the sharing of any market information with LG&E other than information it had committed to make available to non-affiliated marketers and brokers.¹²⁹

3. Power Exchanges

In August 1994, the Commission disclaimed jurisdiction over a computerized brokerage and bulletin-board information service offered by Continental Power Exchange, Inc., a wholly-owned subsidiary of Iowa-Illinois Gas & Electric Company. The service would match hourly power and transmission services across the nation.¹³⁰ Continental proposed a rate schedule for the terms and conditions of its brokering service, as well as cost-based ceiling formula rates for the hourly services that Central Illinois Public Service Company (Central Illinois), its only customer at the time, would provide to other customers. The FERC directed Central Illinois to file a revised rate schedule for the services it will provide, excluding Continental's services.

Utilities using the brokering service may charge any Commission-approved rate. Most of the objections raised by intervenors related to possible effects on system reliability when Continental arranges transmission paths for brokered exchanges of power. The FERC left it to the owners and operators of the transmission system to address reliability concerns.

G. Exempt Wholesale Generators

The Public Utility Holding Company Act (PUHCA) Section 32(a)(1) states that "[n]o person shall be deemed to be an exempt wholesale generator under this section unless such person has applied to the Federal Energy Regulatory Commission for a determination under this paragraph."¹³¹ FERC regulations implement this statutory provision by detailing the requirements that each exempt wholesale generator (EWG) applicant¹³² must meet and the procedure that each EWG applicant must follow to secure a favorable determination on EWG status. Over the course of the

128. *Id.* at 62,121, 62,122.

129. *Id.* at 62,123.

130. *Continental Power Exch., Inc.*, 68 F.E.R.C. ¶ 61,235, at 62,105 (1994).

131. 15 U.S.C. § 79z-5a(a)(1) (1994).

132. "[T]o the extent that applicants are separate companies . . . each must file a separate application." 58 Fed. Reg. 8897, 8905 (1993) (supplemental information accompanying the FERC's issuance of 18 C.F.R. subch. T, pt. 365). Thus, only one person may seek an EWG determination per application. See *Costanera Power Corp.*, 61 F.E.R.C. ¶ 61,335 (1992).

past two years, the FERC has considered numerous EWG applications that have required it to interpret both the statutory requirements contained in PUHCA Section 32 and its own implementing regulations.

1. EWG Eligibility

An EWG applicant must demonstrate in its application that it is a "person":

[E]ngaged 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.¹³³

Failure to address each of the particular requirements contained in this definition will lead the FERC to deny the EWG application.¹³⁴

a. The Applicant

An EWG application must be filed by a "person," as defined in PUHCA Section 2(a)(1)—meaning either an individual or a company.¹³⁵ In turn, "company" is defined to include a corporation, partnership, association, joint-stock company, business trust, or group of individuals (whether or not incorporated), and any receiver, trustee, or other liquidating agent of the foregoing.¹³⁶ In the case of corporate applications, the FERC requires that the EWG applicant exist at the time of the filing.¹³⁷

b. Permissible Business Activities

An EWG applicant must engage, either directly or indirectly through an affiliate, in the business activities specified in PUHCA Section 32(a)(1)—*i.e.*, to be engaged exclusively¹³⁸ in the ownership and/or operation of eligible facilities coupled with the sales of electric energy at wholesale. However, the FERC has expanded the permissible list of business activities, by defining the "exclusivity" requirement to include incidental retail sales of steam,¹³⁹ fly-ash,¹⁴⁰ and certain by-products of incineration.¹⁴¹ In addition, the FERC permits an EWG to engage in the following

133. PUHCA Section 32(a)(1), 15 U.S.C. § 79z-5a(a)(1) (1988).

134. See *Northern Mindanao Power Corp.*, 65 F.E.R.C. ¶ 61,374 (1993) (application denied for failure to state that applicant will sell electric energy at wholesale or that applicant will enter into an agency relationship with another person who will make such sales); *Southern Elec. Wholesale Generators, Inc.*, 63 F.E.R.C. ¶ 61,050 (1993) (application denied for failure to identify an "affiliate" as that term is defined in PUHCA Section 2(a)(11)(B)).

135. 15 U.S.C. § 79b(a)(1) (1994).

136. 15 U.S.C. § 79b(a)(2) (1994).

137. *Nevada Cogeneration Ass'n. #5*, 65 F.E.R.C. ¶ 61,127 (1993).

138. An EWG applicant must demonstrate that, in addition to owning and/or operating an eligible facility and selling electric energy produced by that facility at wholesale, it will be engaged exclusively in that business. See *NW Energy (Williams Lake) Ltd.*, 62 F.E.R.C. ¶ 61,235 (1993).

139. *Brooklyn Energy Ltd.*, 66 F.E.R.C. ¶ 61,113 (1994).

140. *Richmond Power Enter., Ltd.*, 62 F.E.R.C. ¶ 61,157 (1993).

141. *Elm Energy & Recycling (UK) Ltd.*, 63 F.E.R.C. ¶ 61,201 (1993).

activities associated with the development and acquisition of ownership interests in as-yet-unidentified eligible facilities and/or EWGs:

[D]ue diligence, project design review or development, preparation of bid proposals, application for required permits and/or regulatory approvals, negotiation of agreements to sell electricity at wholesale, negotiation of contractual commitments with lenders and equity investors, and other such activities as may be required to achieve financial closing on an eligible facility and/or EWG;¹⁴²

[S]ubmission of bid proposals, . . . negotiation of agreements to sell electric energy . . . , and negotiation of contractual commitments with . . . governmental authorities and other project participants. . . .¹⁴³

c. Ownership and/or Operation of Eligible Facilities

An EWG applicant must demonstrate that it owns and/or operates one or more “eligible facilities.” Subject to the limitation regarding “existing rate-based facilities,” for which State consent is required,¹⁴⁴ an eligible facility is defined in PUHCA Section 32(a)(2) as:

[A] facility, wherever located, which is either (a) used for the generation of electric energy either exclusively for sale at wholesale, or (b) used for the generation of electric energy and leased to one or more public utility companies. . . . Such term includes interconnecting transmission facilities necessary to effect a sale of electric energy at wholesale.¹⁴⁵

The FERC will approve an EWG application when the eligible facility simultaneously meets the requirements for a “qualifying facility,” as defined in the Public Utility Regulatory Policies Act (PURPA).¹⁴⁶ The only type of non-generating facilities considered part of an eligible facility are interconnecting transmission facilities necessary to effect a sale of electric energy at wholesale,¹⁴⁷ or necessary for foreign retail sales.¹⁴⁸

The term “facility” is further defined in PUHCA Section 32(a)(2) to “include a portion of a facility,” subject to the limitation regarding “hybrid facilities” for which state consent is required,¹⁴⁹ as well as “a facility the

142. *Southern Elec. Wholesale Generators, Inc.*, 66 F.E.R.C. ¶ 61,264 (1994).

143. *Entergy Power Asia Ltd.*, 67 F.E.R.C. ¶ 61,342 (1994) (permissible business activities also included those identified in *Southern Elec. Wholesale Generators, Inc.*, 66 F.E.R.C. ¶ 61,264.).

144. If a rate or charge (other than those involving the recovery of wholesale costs) for a facility, or for its construction, or for electricity produced therein, were in effect in any State as of October 24, 1992, *i.e.*, existing rate-based facilities, then, in order to qualify as an eligible facility, all affected State commissions must have concluded that such status: (1) will benefit consumers; (2) is in the public interest; and, (3) does not violate State law. PUHCA Section 32(c), 15 U.S.C. § 79z-5a(c) (1988). *Accord Adirondack Hydro Dev. Corp.*, 66 F.E.R.C. ¶ 61,059 (1994) (involving the lease of an existing rate-based facility site for use by an eligible facility).

145. 15 U.S.C. § 79z-5a(a)(2) (1994).

146. See 16 U.S.C. § 796(17)(C), (18)(B) (1994). See also *Richmond Power Enter., Ltd.*, 62 F.E.R.C. ¶ 61,157 (1993).

147. *Desarrollo Petacalco*, 67 F.E.R.C. ¶ 61,403 (1994).

148. *1069284 Ontario Inc.*, 68 F.E.R.C. ¶ 61,069 (1994).

149. A “hybrid facility” is one in which the facility is owned and/or operated in part by an electric utility company that is an affiliate or an associate company of an EWG. PUHCA Section 32(d), 15 U.S.C. § 79z-5a(d)(1) (1994). In such instances, in order for the facility to qualify as an eligible facility, all affected State commissions must conclude that such status (1) will benefit consumers; (2) is in the

construction of which has not been commenced or completed.”¹⁵⁰ The FERC has also interpreted the term “facilities” to include only physical generating assets—not paper assets such as power sales contracts, corporate books, or other financial records (even though the latter may be used in conjunction with physical generating assets to accomplish the sale of electric energy at wholesale).¹⁵¹

Congress has indicated that an EWG applicant can own and/or operate facilities other than those associated with the generation, transmission, and distribution of energy so long as such facilities are “reasonably necessary for the operation of its business.”¹⁵² In addition, the FERC has concluded that ownership and/or operation of a discrete and separate facility that is merely ancillary to an eligible facility, *e.g.*, a coal handling facility, without ownership and/or operation of the generating facility itself is insufficient to confer EWG status.¹⁵³

d. Sales of Electric Energy at Wholesale

An EWG applicant must also demonstrate that it will be engaged in “selling electric energy at wholesale,” a term defined in PUHCA Section 32(a)(3), and by reference to section 201 of the FPA, to mean the “sale of electric energy to any person for resale.”¹⁵⁴ This requirement is sufficiently broad to permit sales of electric energy at wholesale from eligible facilities owned and/or operated by an EWG, as well as sales of electric energy at wholesale from facilities owned and/or operated by other parties.¹⁵⁵ The FERC interprets this requirement to include situations in which the EWG applicant operates the eligible facility pursuant to the control, direction, and decision-making authority of another person who owns the facility and in turn sells the power produced by the facility at wholesale, *e.g.*, where the operator and the owner of an eligible facility are two separate entities in an agency relationship through implementation of an operations and maintenance agreement.¹⁵⁶ Likewise, the FERC permits the lease of an eligible facility by an EWG to qualify as a sale of electric energy at wholesale absent a case-specific determination that to do so could harm the public interest.¹⁵⁷

public interest; and, (3) does not violate State law. PUHCA Section 32(d)(2), (c), 15 U.S.C. § 79z-5a(d)(2), (c) (1994).

150. 15 U.S.C. § 79z-5a(a)(2) (1994).

151. *Louis Dreyfus Elec. Power Inc.*, 62 F.E.R.C. ¶ 61,234, at 62,579 (1993).

152. H.R. CONF. REP. NO. 1018, 102d Cong., 2d Sess. 388 (1992), *reprinted in* 1992 U.S.C.C.A.N. 2472, 2479.

153. 67 F.E.R.C. ¶ 61,403, at 62,367.

154. 16 U.S.C. § 824(d) (1988).

155. H.R. CONF. REP. NO. 1018 at 388.

156. *Enron Milford Operating Corp.*, 63 F.E.R.C. ¶ 61,063 (1993).

157. See 58 Fed. Reg. 21,250, 21,254 (1993) (supplemental information accompanying FERC's revisions to 18 C.F.R. pt. 365). See also *Las Vegas Energy Storage Ltd.*, 64 F.E.R.C. ¶ 61,181 (1993).

Specifically exempted from this requirement are foreign retail sales from eligible facilities located in a foreign country, provided that none of the electricity generated from such facilities is sold to retail customers in the United States.¹⁵⁸ The FERC has concluded that an Indian reservation located within a "State" and the "United States" (as both terms are defined in PUHCA Sections 2(24) and 2(25)) is not a "foreign country" and thus cannot take advantage of this exception.¹⁵⁹

2. FERC Filing Requirements

a. Applications and Withdrawals

An EWG application filed in good faith at the FERC affords the applicant interim status as an EWG until such time as the FERC makes its determination,¹⁶⁰ which must be completed within sixty days of its receipt of the application; otherwise the application will be deemed granted.¹⁶¹ Since the FERC does not permit the filing of amendments and will not issue deficiency letters requesting additional information,¹⁶² an applicant that discovers a defect in its application may withdraw it pursuant to rule 216(b),¹⁶³ or simply await FERC denial. A withdrawal is not effective (absent FERC action) for at least fifteen days; thus, in situations where the withdrawal deadline falls after the 60-day review deadline, and where good cause is shown, the FERC will waive the time period provided in rule 216(b).¹⁶⁴

b. Intervention

The FERC publishes each EWG application in the Federal Register to permit public notice and comment or intervention.¹⁶⁵ The FERC will grant a motion to intervene, even when opposed by the EWG applicant, provided the intervenor (i) expresses an interest not represented in the proceeding by another party; and, (ii) demonstrates that its participation is in the public interest.¹⁶⁶ The FERC will also grant an untimely motion to intervene if the delay in the filing is short, the motion is not opposed, and no prejudice arises from such late intervention.¹⁶⁷ In any event, however, the scope of intervention is limited to "information concerning the adequacy or accuracy of the factual representations made to satisfy the statutory criteria for EWG status" and *not* to involve issues such as "a facility's

158. PUHCA Section 32(b), 15 U.S.C. § 79z-5a(b) (1994).

159. *John J. Wheeling*, 65 F.E.R.C. ¶ 61,164, at 61,837 (1993).

160. 18 C.F.R. § 365.4 (1995).

161. 18 C.F.R. § 365.5 (1995).

162. See 58 Fed. Reg. at 8,903, n.30.

163. See 18 C.F.R. § 385.216(b) (1995).

164. See *ESBI Energy O&M, Inc.*, 66 F.E.R.C. ¶ 61,110 (1994).

165. See 18 C.F.R. §§ 365.3(c), 385.211, 385.214 (1995).

166. 65 F.E.R.C. ¶ 61,164, at 61,836.

167. *Blue Diamond Power Partners, Ltd.*, 64 F.E.R.C. ¶ 61,321, at 63,363 (1993).

financing arrangements or . . . the environmental consequences of a facility's construction or operation."¹⁶⁸

c. Supplemental Filings

Once its status is approved, the EWG is under a continuing obligation to inform the FERC "[i]f there is any material change in facts that may effect an EWG's eligibility for EWG status. . . ."¹⁶⁹ Thus, if an EWG desires to engage in additional activities not covered by its original application and FERC determination, an additional application must be filed at the FERC.¹⁷⁰

A party whose EWG application is denied may (1) file a new application with additional information or explanation;¹⁷¹ (2) file a petition for reconsideration;¹⁷² or, (3) seek judicial review in U.S. district court under PUHCA Section 25, alleging that the FERC violated PUHCA Section 32 or its own implementing regulations.¹⁷³

H. Nuclear Decommissioning Trust Fund Guidelines

In a Notice of Proposed Rulemaking (NOPR) issued May 25, 1994, the FERC proposed three alternative guidelines for nuclear plant decommissioning fund (Fund) investments.¹⁷⁴ Since issuing the NOPR, the FERC has approved a utility's proposed settlement plan that includes investments not covered in the Black Lung standard. However, the Commission stated that its decision is subject to whatever guidelines are adopted in the final rule and should not be viewed as precedent.¹⁷⁵

1. The Black Lung Investment Standard

In 1986, the FERC established guidelines for public utilities to create nuclear decommissioning funds and invest Fund assets.¹⁷⁶ The Commission used Internal Revenue Service (IRS) guidelines for such Fund investments,¹⁷⁷ which guidelines were identical to (Internal Revenue Code) standards for Black Lung Disability Trusts.¹⁷⁸ The FERC regulations apply only to the investment of Fund assets collected from wholesale customers. Fund assets collected from retail customers are regulated by state agencies.

168. 58 Fed. Reg. at 8899-8900.

169. 18 C.F.R. § 365.7 (1995).

170. 66 F.E.R.C. ¶ 61,264.

171. 58 Fed. Reg. at 8903, *as corrected* 58 Fed. Reg. 11,886 (1993).

172. As a matter of discretion, the FERC can grant such a petition and decide whether to reconsider its previous determination. 67 F.E.R.C. ¶ 61,403.

173. 58 Fed. Reg. at 8904.

174. The Fund's initial assets are collected from customers, usually in the form of a surcharge. 59 Fed. Reg. 28,297 (1994) (to be codified at 18 C.F.R. part 35) (proposed June 1, 1994).

175. *Vermont Yankee Nuclear Power Corp.*, 68 F.E.R.C. ¶ 61,284 (1994).

176. *Systems Energy Resources, Inc.*, 37 F.E.R.C. ¶ 61,261 (1986).

177. 26 U.S.C. § 486A(e)(4) (1988).

178. IRC § 486A(e)(4) cross-references § 501(c)21 which sets investment standards for Black Lung Disability Trusts. 26 U.S.C. § 486A(e)(4) (1988).

The Black Lung standard limits investments to (i) public debt securities of the United States; (ii) obligations of a State or local government which are not in default as a principal or interest; and, (iii) time or demand deposits in a bank, trust company, or credit union. The FERC implemented a limited risk standard to guarantee that funds would be available when decommissioning takes place.

2. EPCRA's Elimination of the *Black Lung* Standard for Funds and Subsequent FERC Action

The Energy Policy Act of 1992 (EPCRA) repealed a portion of IRC Section 486A(e) that had limited the types of Fund investments to those articulated in the Black Lung standard. The IRC restriction was eliminated in the belief that public utilities and State regulatory agencies should determine appropriate types of investments.¹⁷⁹ Indeed, when the IRS issued a final rule modifying the IRC to reflect Congress' changes, it stated that removing the IRC Black Lung requirement shifted oversight of Fund investments to the public utility commissions.¹⁸⁰

In *Systems Energy Resources, Inc. (Systems Energy II)*,¹⁸¹ the FERC clarified its policy regarding Fund investments. It concluded that the existing Black Lung standard remained the most appropriate investment policy because its conservative provisions guarantee that sufficient funds will be available at the time of decommissioning.¹⁸² The FERC can approve an investment plan that deviates from the Black Lung standard if the public utility can demonstrate that the proposal "offers equal or greater assurance of the availability of funds at the time of decommissioning and is at least as beneficial to consumers as are the [Black Lung] guidelines."¹⁸³

Following *Systems Energy II*, several public utilities and utility commissions filed requests for rehearing. The parties argued that the Black Lung guidelines (1) are not a guarantee against loss; (2) increase the risk that returns will be insufficient to meet decommissioning obligations; (3) increase costs to ratepayers; (4) are inconsistent with Congressional intent; and, (5) will increase administrative and litigation costs because of discrepancies between the FERC and state guidelines.¹⁸⁴

3. FERC's Proposed Investment Guidelines

The FERC proposes to amend part 35 of volume 18 of the Code of Federal Regulations by adding a new subpart E which will set forth the

179. H.R. REP. NO. 474, 102d Cong., 2d Sess. 6 (1992).

180. 57 Fed. Reg. 62,198 (1992).

181. *Systems Energy Resources, Inc.*, 65 F.E.R.C. ¶ 61,083 (1993).

182. *Id.* at 61,513.

183. *Id.* at 61,514.

184. 59 Fed. Reg. 28,297, 28,299 (1994) (to be codified at 18 C.F.R. pt. 35) (proposed June 1, 1994). Contemporaneous with issuing its NOPR on Fund Guidelines, the FERC denied requests for rehearing, electing instead to treat the rehearing requests as comments on the NOPR and inviting parties to submit additional comments if desired. *Id.* nn.10-11.

Nuclear Plant Decommissioning Guidelines.¹⁸⁵ The guidelines provide that the Fund must be an external trust fund.¹⁸⁶ The Trustee must be independent of the utility, have a net worth of at least \$100 million, and exercise the care of a reasonable person under the same circumstances. The Trustee must limit Fund investments to those allowed by the FERC and must not invest in any securities of the utility, its subsidiaries, affiliates, or associates. If the Fund balance exceeds the costs of decommissioning, the utility must make refunds to ratepayers in a manner approved by the Commission after completion of decommissioning.

The final guidelines will implement one of the three alternative investment standards the FERC has proposed:

(1) *Alternative 1* offers no change to existing standards; the FERC would continue to use the Black Lung guideline.¹⁸⁷

(2) *Alternative 2* allows a Trustee to invest Fund assets while exercising "the same standard of care that a reasonable person would exercise in the same circumstances," with no other express guidelines.¹⁸⁸

(3) *Alternative 3* would adopt the "reasonable person standard" (as in *Alternative 2*), but also set guidelines as to the quality of investments and the portion of Fund assets which may be placed in particular types of investments.¹⁸⁹

4. FERC Action Following the Proposed Standards

In early September, the FERC approved a settlement, proposed by Vermont Yankee Nuclear Power Corporation, which included Fund investment strategies not contained in the Black Lung guidelines.¹⁹⁰ The FERC cautioned, however, that the *Vermont Yankee* order should not be considered precedent; and it further advised the utility that it must (i) comply with any Fund investment guideline promulgated in the Final Rule; and, (ii) adjust its investment strategy accordingly if it does not meet FERC's final standards.¹⁹¹

185. *Id.* at 28,209.

186. *Id.* at 28,300.

187. *Id.*

188. *Id.* at 28,302. In the context of a review of the prudence of a utility's decisionmaking, the FERC has evaluated a utility's decision based upon that which "reasonable utility management . . . would have made, in good faith, under the same circumstances, and at the relevant point in time." *New England Power Co.*, 31 F.E.R.C. ¶ 61,047, at 61,084 (1985). The FERC requested comments addressing whether this prudence standard is appropriate when reviewing Fund investment strategies or whether an alternative standard should be adopted. 59 Fed. Reg. 28,297 at 28,298 (1994).

189. 59 Fed. Reg. 28,297, at 28,302 (1994) (to be codified at 18 C.F.R. § 35.33(a)(3)) (proposed June 1, 1994).

190. Vermont Yankee will invest up to 30% of its Fund in equities and the remaining 70% split evenly between corporate bonds and Treasury bills.

191. 68 F.E.R.C. ¶ 61,284.

II. STATE ACTIVITY

A. *Retail Wheeling*

Several states considered retail wheeling matters during 1994. Retail wheeling involves the use of a utility's transmission lines to transport electric power purchased by a utility customer from some entity other than the utility itself. A brief description of various state efforts is set forth below.

1. Arizona

On May 20, 1994, the Arizona Corporation Commission initiated a generic proceeding to discuss the relationship between competition and the provision of electric services. Among the issues discussed during a workshop on the retail wheeling issue were: (1) the cost of transmission access; (2) reliability; (3) access to low cost suppliers; (4) jurisdiction; (5) stranded costs; (6) demand-side management (DSM) and integrated resource planning (IRP); (7) environmental policies; (8) renewable energy; (9) the traditional notions of the "regulatory compact" and the "obligation to serve"; (10) alternative methods of obtaining low cost power; and, (11) benefits versus costs in the long-term and the short-term.

The Arizona Corporation Commission also approved an Arizona Public Service Company settlement that includes an agreement between the utility and the Commission staff to undertake a study of alternative/competitive pricing methods.

2. Illinois

The Illinois Commerce Commission is awaiting the report of the Illinois Regulatory Initiatives Task Force. It is anticipated that the Task Force will analyze the policy ramifications of competition in the electric utility industry, as well as the need for regulatory and legislative change to effect competition. Two separate working groups were formed to address these broad issues. The mission statement of the Task Force suggests that the following issues would be considered: (1) retail wheeling; (2) unbundling; (3) the traditional notion of the "obligation to serve"; (4) stranded costs; (5) incentive regulation; (6) transition costs, cost shifting, and cross-subsidization; and, (7) pricing.

3. Indiana

PSI Energy, an Indiana utility, announced that the company's forty largest customers may be offered the opportunity to engage in retail wheeling. This initiative would encompass proposals for these customers to continue to purchase some portion of their power needs from PSI Energy, as well as opportunities for them to leave the PSI system entirely. PSI Energy is expected to file its plan with the Indiana Utility Regulatory Commission.

4. Iowa

On June 8, 1994, the Iowa Utilities Board convened a conference on retail wheeling. The policy issues discussed included technical, legal, and legislative barriers to retail wheeling. One such issue encompasses the conflict between federal and state jurisdiction over transmission pricing and the state's ability to require or authorize retail wheeling.

5. Massachusetts

Retail wheeling and competition issues were addressed in Massachusetts, including legislative and policy forums. As in several other states, while retail wheeling was not always described as the focus of the discussion, the proposals discussed tend to encompass retail wheeling in their implementation.

The Electric Utility Market Reform Task Force issued a report in July 1994, in which increased competition and regulatory reform were recommended for the wholesale electricity sector. The task force also recommended that a study of retail wheeling be undertaken. In their recommendation, the Task Force noted several issues associated with competition in the retail electricity sector, including the conflict between traditional notions of regulation and obligations to the captive customer, the utility's obligation to serve, and access to electric services. Other issues identified as important in any study of retail sector competition include the price of electricity, energy efficiency, and the need to consider environmental factors.

The Massachusetts Bay Transportation Authority (MBTA) was designated a public utility under Massachusetts state law and, therefore, permitted to engage in transactions consistent with notions of retail wheeling. The MBTA can obtain competitively priced electric power from any supplier and have that power wheeled over one of the local utilities' lines. In addition to its relevance to retail wheeling, the MBTA matter raised such issues as federal and state jurisdiction and stranded costs.

6. Michigan

Detroit Edison filed suit in the U.S. District Court for the Western District of Michigan, challenging the State of Michigan's jurisdiction to adopt a retail wheeling experiment. Specifically, Detroit Edison filed a request for a declaratory order that the FERC's jurisdiction over transmission facilities in interstate commerce preempts the Michigan Public Service Commission's exercise of authority over transmission service to retail wheeling customers.

At issue is the Michigan Public Service Commission's April 11, 1994 order approving an experimental retail wheeling program applicable to certain customers located in the service territories of Detroit Edison and Consumers Power Company. While terms and conditions of the experimental retail wheeling service were set forth in that order, the Michigan PSC bifurcated the proceeding to separately consider the applicable rates and

charges for retail wheeling service. The second phase of this proceeding is currently pending before an Administrative Law Judge.

7. Nevada

The Nevada legislature revised its laws governing the regulation of public utilities, their rates, equipment, practices, and facilities, to grant expanded authority to the Nevada Public Service Commission (NPSC). Specifically, the revised statutes authorize the NPSC to permit utilities to engage in the purchase or transmission of electricity for/to certain businesses, when such purchase or transmission is designed to reduce the overall cost of electricity to the business.

8. New Hampshire

The New Hampshire Public Utilities Commission has pending before it a proposal by the Freedom Electric Power Company to render service that mirrors retail wheeling. The filing requests limited authority to receive and deliver electric power over the transmission system of Public Service Company of New Hampshire. The electric power would be delivered to certain large end-use customers currently served by Public Service Company of New Hampshire.

9. New Mexico

Retail wheeling is being considered by a legislative committee that has conducted several levels of hearings. In 1993, efforts to enact several bills authorizing retail wheeling were unsuccessful; instead, a study of retail wheeling was commissioned by a joint committee of the state House and Senate. That joint committee continued to hold hearings during 1994.

10. New York

The Public Service Commission of New York has been involved in an ongoing effort to investigate competition in the wholesale and retail electricity sectors. The Commission hopes to adopt a statement of principles designed to achieve a smooth transition to a more competitive market. Financial considerations, stranded costs, service reliability and affordability, pricing, and environmental concerns are among the issues to be encompassed in these principles.

11. Pennsylvania

By order issued May 10, 1994, the Pennsylvania Public Utilities Commission initiated an investigation concerning competition and retail wheeling. Among the issues to be addressed in the investigation are federal/state jurisdiction, stranded costs, the effect of competition and retail wheeling on captive customers and other customers who remain on the system, the traditional role of the utility's "obligation to serve," pricing, criteria under which to assess the competitiveness of markets, unbundling, and any impact on the power pool.

12. California

On April 20, 1994, the California Public Utilities Commission (CPUC) issued an "Order Instituting Rulemaking and Order Instituting Investigation." The pending rulemaking and investigation proceedings were a follow-up to a report issued in February 1993, entitled "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future" (also known as the "Yellow Book"). It initiated the process of examining the structure and regulatory policies affecting the electric services industry in California. The April 1994 rulemaking (or "Blue Book") proceeding sought comment and evidence on regulatory policy reform and industry restructuring.

Among the factors prompting the CPUC's initiative was its desire to foster economic growth, enhance competitiveness, and increase business opportunities in California. Still, the CPUC intends that its policy reform and restructuring goals be undertaken over the long-term and in a manner designed to avoid litigation, where possible, by using alternative issue resolution mechanisms.

The CPUC originally proposed initial implementation of retail wheeling—or "direct access"—as of January 1, 1996 for the largest utility customers. Subsequent regulatory treatment of direct access customers would reflect a substantial departure from traditional notions of cost-of-service type regulation. Sales of power to such customers would instead be governed by competitive market forces. Direct access service would be available initially only to customers receiving service at a minimum of 50 kilovolts. Participation as a direct access customer would be entirely voluntary, and regulated utilities would be required to provide transmission and distribution services on a nondiscriminatory basis as needed by individual direct access customers.

Direct access customers choosing to return to traditional bundled electric service from a utility would be required to give not less than twelve months notice to the utility, although the utility would have discretion to waive any or all of the notice requirement. If no waiver were granted by the utility and the customer seeks to return to the system with less than twelve months' notice, the utility would not be obligated to offer service to such customer at the filed tariff rate. Instead, the utility would be allowed to recover its incremental costs incurred in providing service during the interim period between the customer's return to the system and the expiration of the 12-month notice period. A customer would be required to give not less than twelve months' notice before returning to direct access status. The California PUC envisions making direct access status available to all electric utility customers by January 1, 2002.

The CPUC also proposed two levels of regulatory reform. In non-competitive markets traditional cost-of-service regulation would be replaced by "performance-based regulation." The CPUC is willing to allow each utility to make its own proposals as to how to implement performance-based regulation, some of which have already been formulated. However, such proposals must be consistent both with the goals and

requirements ultimately adopted in the CPUC's final order and with any legislative requirements in effect now or at the time that the utility's proposal is approved. In competitive markets, or markets in which the potential for competition exists, market forces would be allowed to govern.

The CPUC anticipates that the principles governing its new policy would include (1) allowing the utility to compete to retain direct access consumers based on disaggregated prices and services; (2) allowing the utility to negotiate with direct access customers prices that diverge from tariff rates for generation and generation-related services, so long as such prices neither exceed the filed tariff rate nor fall below the utility's marginal cost; (3) a requirement that a floor and ceiling be devised to govern utility earnings, which would ensure that utility shareholders share in the costs and the benefits of a shift to competition; and, (4) contribution by direct access customers to any uneconomic portion of the utility's generating assets that arise as a result of a shift to competition, through a competition transition charge that would be assessed as part of the demand charge.

Additionally, the CPUC has acknowledged that it will need to help mitigate any increased financial exposure that utilities face due to implementation of a competitive framework for electric utilities. The Commission also reaffirmed its commitments (1) to aggressive efforts to promote investment in cost-effective energy efficient services; (2) to system control and coordination, and the utility's obligation to provide safe and reliable service; and, (3) to social goals such as investment in electric and alternative fuel vehicles, assistance to low-income consumers, and rate structures that promote economic development. The CPUC acknowledged, however, that its commitment to these goals will need to be reevaluated in light of its proposals for industry restructuring and policy reform.

13. Connecticut

The Connecticut Department of Public Utility Control (DPUC) instituted a generic investigation into the need for and the effect of retail wheeling in the state; and, it issued a final decision on September 9, 1994.

Connecticut initially undertook to investigate electric transmission service issues in 1987. In a report issued on April 14, 1987, the DPUC concluded that it would have the authority to order retail wheeling once enabling legislation was enacted. Subsequently, in its September 1994 decision, the DPUC stated its belief that it has "sufficient enabling authority . . . to mandate or to approve voluntary retail transmission arrangements," although there is no statute that specifically grants such authority. The Commission also noted, however, that an amendment to section 16-243a(b) of the Connecticut General Statutes would be required to remove limitations on the class of persons eligible to receive electric energy from private producers, or to expand the class of electricity suppliers allowed to engage in direct sales.

The DPUC's September 1994 decision identified certain persistent factors requiring serious consideration of retail wheeling, including (1) consumer demand for rate relief, due to high electric rates and low wholesale

power rates; and, (2) increased requests for customer-specific industrial rates, which the DPUC has granted in the past.

The DPUC believes that, prior to authorizing retail wheeling, the costs, benefits, and risks of retail wheeling should be given thorough consideration. Included would be a determination of the effect and benefits to residential and small commercial customers, large commercial and industrial customers, low income consumers, the utilities and their shareholders, and the economy. Social and public policy obligations—such as environmental effects of generation, fuel diversity, system reliability, resource conservation, and impact on attracting and retaining businesses—are also considered important in determining the overall cost/benefit impact of retail wheeling.

The Connecticut DPUC asserts that it is not currently considering unbundling electric services. Recognizing that unbundling would require development of separate rates for the separate costs of generation, distribution, and transmission, as well as for services such as back-up power and reactive power, the DPUC noted that consideration would have to be given to the downside risks of disaggregation. Included among such downside risks are (1) exposure of subsidiary utility functions to greater risk; (2) requiring management to optimize and discipline utility operations; and, (3) requiring utility management to bear liability for the consequences of its decisions. In sum, the DPUC's view is that these downside factors have the potential to increase financial risk and/or failure, and should therefore be considered very carefully. As a result, retail wheeling under the Connecticut proposal would be limited to "the sale of electricity directly from a generator to an end user over transmission lines owned by a third party."

Other services viewed by the DPUC as unsuitable for unbundling are responsibility for overall reliability and quality of service (*i.e.*, system monitoring, management, and coordination) and the cost of such services and obligations. The DPUC views these functions and services as the obligation of the utility, even if retail wheeling were authorized.

The DPUC reported significant support for retail wheeling to be offered only to those customers whose loads exceed one megawatt. The agency found no analyses demonstrating the benefits expected to be achieved by extending the retail wheeling option to customers with loads less than one megawatt.

The DPUC concluded that although it has authority to require direct sales to ultimate electric consumers, and although retail wheeling is technically feasible, it should be undertaken only when there is a need for capacity. Implementing retail wheeling prior to the need for new capacity, it concluded, would be contrary to the State Energy Policy, and would foster production inefficiencies, increase stranded costs, use an excess of non-renewable resources, disrupt implementation of the Clean Air Act, and adversely affect the IRP process.

14. Wisconsin

The Public Service Commission of Wisconsin (PSCW) issued a report on retail wheeling and competition roundtable discussions in September 1994. The report notes several differences between Wisconsin and other states considering the retail wheeling issue. For example, the September 1994 report asserts that electric rates to all customer classes in Wisconsin are very low as compared to the national average. The roundtable report also notes that, as compared with several other states, including California, the electric power industry in Wisconsin "is at a moderate level of competitive development."

The roundtable report addressed both competition and industry restructuring issues, and noted that the distinction between retail wheeling and comprehensive retail competition must be considered in evaluating available options. According to the report, retail wheeling encompasses the ability of retail customers of a utility to purchase electricity and have that electricity transported over the transmission lines of the local utility. On the other hand, the report identifies the following indicia of comprehensive retail competition: (1) numerous supply and demand options in addition to purchasing electricity from the utility; (2) numerous sellers of such supply and demand options; and, (3) access among buyers and sellers of electric services.

The roundtable commenters generally agreed that greater reliance on competitive forces in the generation sector of the electric utility business is important. The report notes further that the Commission's current policies on capacity procurement, rate base regulation, IRP, and organizational structure will have to be considered in the context of the amount of flexibility and the level of any incentive to be given existing utilities participating in the electricity generation market sector. Suggestions for developing competition in the generation services market were (1) decentralized competitive bidding; and, (2) fostering competition and efficiency for energy and capacity in both regional and national markets.

Restructuring electric utility generation services was described as a necessary component to allowing increased competition in the generation sector. Among the options described in the report are (1) separate accounting and regulatory treatment for utility-owned generation assets; (2) consideration of whether generation assets should remain in the rate base; (3) creating a separate corporate entity for generation assets; and, (4) divestiture of existing generation.

The report also describes three options that could be used to effect structural separation. In the first option, only new generation would be restructured. The report notes that pursuit of this option would necessarily make complete restructuring an extremely long-term venture because the rate base would be reduced only as old and recently constructed plants are retired. The second option would require that all generation be restructured. The report notes, however, that a variety of legal and public policy questions would arise from pursuit of this alternative (*e.g.*, amending the law to allow for such transfer, plus heightened PSCW oversight of the

potential for cost-shifting). Under the third option, only new generation would be restructured initially. Existing generation would be gradually phased-in to retail wheeling, and a proportional amount of existing generation assets would be transferred.

While noting the need to resolve issues such as stranded investment, reciprocity and regional retail wheeling, effects on the utility's "obligation to serve," system planning and coordination, pricing, terms and conditions, and cost allocation, the roundtable report suggests several procedural options for furthering discussion of retail wheeling. Those options include: (1) issuing a Notice of Inquiry (NOI) for comments and data to address the regulatory policy issues; (2) commencing full-panel PSCW hearings following receipt and review of comments and data from the above NOI; (3) instituting a generic proceeding to consider the policy issues; (4) instituting a rulemaking proceeding to adopt the general policy that would govern retail wheeling; (5) identifying and proposing legislative changes needed to implement retail wheeling and generation market competition; (6) using alternative dispute resolution in lieu of trial-type resolution of disputed cases in which restructuring and competition are proposed; and, (7) working with the National Association of Regulatory Commissioners, regional regulatory councils, and others to implement restructuring and competition on a regional and national basis.

15. Conclusion

Common threads run through the states' approaches to the retail wheeling issue. Those common threads include regulatory issues such as: (1) protection of "core" customers; (2) whether and how to unbundle the various services offered by regulated utilities; (3) the pricing of such services; (4) the nature of any impact on the obligation of the utility to serve (embodied in the traditional regulatory compact, which also includes cost-of-service regulation and the opportunity to earn a fair rate of return); (5) the effect on social policies such as IRP/DSM and service to low income and hardship customers; (6) cost shifting; and, (7) environmental efficiency.

None of the comments and undertakings in the various jurisdictions have considered technical issues to be an impediment to implementation of retail wheeling. However, commenters did consistently question the legal ability of the state and/or public utility commission to authorize or require retail wheeling.

Additional reports are due to be issued in 1995 by the various states, and many states have legislation pending that would address the panoply of issues involved in assessing retail wheeling. While studies abound, only a small minority of states are actively proceeding at this time with implementation of some form of retail wheeling, industry restructuring and/or competition in the generation of electric energy.