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PURPA and the Evolving Regulation of Cogeneration--A Guide for Prospective Cogenerators Focusing on the Greater Detroit Resource Recovery Facility

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PURPA AND THE EVOLVING REGULATION OF COGENERATION—A GUIDE FOR PROSPECTIVE COGENERATORS FOCUSING ON THE GREATER DETROIT RESOURCE RECOVERY FACILITY

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Table of Contents

I.	INTRODUCTION	1052
II.	UTILITY REGULATORY FRAMEWORK.....	1056
	A. <i>Pre-Commission Regulation</i>	1057
	B. <i>State Commissions</i>	1058
	C. <i>Federal Regulation</i>	1059
III.	PURPA	1059
	A. <i>In General</i>	1059
	B. <i>Constitutionality of PURPA</i>	1061
	C. <i>FERC Regulations</i>	1063
	1. <i>Market Regulation</i>	1063
	2. <i>Qualifying Facilities</i>	1064
	3. <i>Interconnection and Wheeling</i>	1067
	D. <i>Validity of FERC Regulations</i>	1068
	E. <i>State Implementation of PURPA</i>	1072
	1. <i>In General</i>	1072
	2. <i>Purchase of QF Power</i>	1073
	a. <i>The Energy Credit</i>	1076
	b. <i>The Capacity Credit</i>	1077
	3. <i>Sale of Power to Qualifying Facilities</i>	1080

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4. <i>Interconnection and Wheeling</i>	1082
5. <i>Data Filing</i>	1085
F. <i>Proposed Changes to FERC Regulations</i>	1086
IV. FUEL USE ACT	1092
V. CLEAN AIR ACT	1096
VI. DETROIT COGENERATION PROJECT	1098
A. <i>Detroit's Central Steam Heating System</i>	1099
1. <i>The Project</i>	1099
2. <i>Effect of Federal Statutes</i>	1101
a. <i>PURPA</i>	1101
b. <i>Fuel Use Act</i>	1102
c. <i>Clean Air Act</i>	1103
VII. CONCLUSION	1110

I. INTRODUCTION

In the early 1970s, the United States saw its cheap energy costs disappearing and its strength and security imperiled by a growing dependence on foreign oil.¹ Both the public and private sectors groped for energy saving solutions to check rising costs and reduce oil importation.² Cogeneration emerged as an attrac-

1. During the 20 years preceding the 1973 oil embargo, total energy consumption rose at an annual rate of 3.5%. Petroleum consumption rose 4.0%, more than doubling previous rates. However, domestic petroleum production increased by just 2.1% annually, leading to a growing dependence on imported oil. McCarley & Fichman, *Trends in U.S. Energy Since 1973*, MONTHLY ENERGY REV., May 1983, at i.

In 1973, energy imports supplied 17% of domestic consumption; by 1977, the rate had risen to 23.6%. *Id.* at iii. Petroleum imports reached a peak of 8.6 million barrels in 1977. *Id.* at iv. By 1982, imports dropped to 10.4% of domestic consumption and oil imports fell to 4.2 million barrels per day. *Id.* at iii-iv.

As a result of the oil embargo and the Iranian revolution later in the decade, the cost of a single barrel of petroleum rose from \$4.08 in 1973 to a peak of \$37.05 in 1981. *Id.* at i-ii. Consequently, total energy expenditures continued to rise, even though consumption slowed throughout the 1970s and actually declined beginning in 1978. Energy Info. Admin., *Highlights: Energy Price and Expenditure Data Report, 1970-1980*, MONTHLY ENERGY REV., July 1983, at i. In 1982, total energy expenditures fell for the first time following the energy crisis. Energy Info. Admin., *Highlights: State Energy Price and Expenditure Report, 1970-1982*, MONTHLY ENERGY REV., Mar. 1985, at i.

2. Commentators noted that "[t]he oil embargo, coupled with the explosion of international crude oil prices, revealed U.S. vulnerability to foreign supply disruptions and set in motion profound changes in the pattern of domestic energy consumption and supply." McCarley & Fichman, *supra* note 1, at i. See generally Pratt, *Cogeneration: A Successful Response to the Energy Crisis?*, 9 FORDHAM URB. L.J. 483 (1981); Note, *Public Utility Participation in Decentralized Power Production*, 5 HARV. ENVTL. L. REV. 297 (1981).

tive old technology, but with formidable obstacles to expanded use.³

Conventional powerplants use steam produced from fossil, waste, or nuclear fuel to drive electric generators. Any surplus

3. Cogeneration is the simultaneous production of electricity and heat, usually in the form of steam, from a single fuel source. Both the electricity and heat are used productively to increase the efficiency of fuel use. See FEDERAL ENERGY REGULATION COMMISSION (FERC) STATUTES AND REGULATIONS, REGULATIONS PREAMBLES 1977-1981, at (P) 30,134.

Cogeneration is not a new technology in the United States. In the early part of this century, approximately 50% of the country's electricity was cogenerated. Electricity was produced by reciprocating engines that released steam as a by-product. This exhaust steam provided district heating. The infant electricity industry, as a means of increasing its sales and competing with industrial cogenerators, began to provide both electricity and steam heat to its customers. By 1902, approximately 3600 private and public electric generating systems existed in the United States. Wooster, *Cogeneration: Revival Through Legislation?*, 87 DICK. L. REV. 705, 706-07 (1983).

However, technological changes soon pushed cogeneration into a period of decline that lasted almost 60 years. In 1903, the turbogenerator was developed. Although this unit produced electricity more efficiently, it reduced the quality of waste steam. Additionally, the newly developed alternating current enabled utilities to economically distribute electricity over longer distances, allowing generating facilities to be located further from urban areas. *Id.* at 707.

Through the next several decades, technological advances in producing and distributing steam heat did not parallel the advances made in producing and transmitting electricity. Furthermore, in order to better compete with industrial cogenerators, electric utilities began offering preferential rates to industrial customers. *Id.* at 708.

The environment for cogeneration deteriorated further in the 1940s as the country discovered and used its seemingly inexhaustible supply of natural gas and oil for space heating. INTERNATIONAL ENERGY AGENCY, DISTRICT HEATING AND COMBINED HEAT AND POWER SYSTEMS: A TECHNOLOGY REVIEW 249 (1983) [hereinafter IEA REVIEW]. Urban renewal programs begun in the 1950s also contributed to the demise of cogeneration, as older buildings and the district heating systems attached to them were destroyed. NATIONAL RESEARCH COUNCIL, COMMITTEE ON DISTRICT HEATING AND COOLING, DISTRICT HEATING AND COOLING IN THE UNITED STATES: PROSPECTS AND ISSUES 26 (1985).

During the 1970s, rising fuel costs and restrictive pollution control regulations increased the attractiveness of individual heating systems over the district heating systems used by cogenerators. *Id.* In 1973, it was estimated that industrial cogeneration accounted for only 4.2% of the total United States electric supply. Munson, *The Growing Role of Independent Energy Producers*, 115 PUB. UTIL. FORT., May 30, 1985, at 13. By the end of the decade, industrial generation of electricity and steam declined to less than 4% of the country's energy production. Pratt, *supra* note 2, at 485 n.4 (citing FERC, COGENERATION FACT SHEET 1 (Nov. 1, 1979)).

heat energy is released into the environment.⁴ Cogeneration facilities, on the other hand, use this excess heat productively, substantially increasing the energy system's efficiency. Theoretically, fuel consumption can be halved and production doubled.⁵

Market dynamics and the perishable nature of cogeneration's products, i.e., heat and power, have impeded the growth of this energy system. Developing efficient and economical storage systems for heat and power presents a challenge even more difficult than marketing ice before the advent of refrigeration.⁶ Additionally, although electrical system performance is optimized by a constant rate of operation, the use patterns of heat and power vary by hour, day, and season, inevitably resulting in surplus energy.

Since excess heat can be transported only over relatively short distances, and frequently with considerable capital investment costs, cogeneration systems are most efficient when designed and operated to match the operator's heat needs, with surplus power being sold.⁷ Fortunately for the cogenerator, electricity can be absorbed and managed within an existing utility market—a proposition that the electricity industry has had difficulty accepting.⁸

4. Mogk, *Anglo-American Energy Policy: Combined Heat and Power in the United Kingdom and the United States*, 8 URB. L. & POL'Y 131 (1986).

5. Cogeneration can increase the efficiency of fuel use from 33% to 80%. Casten & Ross, *Cogeneration and Its Regulation*, 107 PUB. UTIL. FORT., Mar. 26, 1981, at 18; Pratt, *supra* note 2, at 486; Note, *Problems with PURPA: The Need for State Legislation to Encourage Cogeneration and Small Power Production*, 11 B.C. ENVTL. AFF. L. REV. 149, 149-50 (1983).

6. One commentator has noted: "Batteries now available cannot economically be constructed to store large amounts of electric energy. Moreover, most batteries have a relatively short life in terms of charge-discharge cycles." Pratt, *supra* note 2, at 498 n.37 (citing *Putting Baseload to Work on the Night Shift*, ELECTRIC POWER RES. INST., Apr. 1980, at 6-9.)

7. A study by the International Energy Agency states:

Many large power stations are located remote from the centres of population for reasons of economy, environmental protection, fuel . . . accessibility and storage, etc. Thus, while the heat available at large power stations may technically be recovered for district heating and may match the demand of a large city, the cost of the transmission line can be prohibitive. At present the maximum economically viable transmission distance is up to . . . 3-5km for steam, depending on the heat load and fuel prices.

IEA REVIEW, *supra* note 3, at 47.

8. The utility industry has been accused of erecting several barriers to the increased use of cogeneration, including: (1) using stonewall negotiating tactics to unnecessarily delay contractual commitments; (2) offering cogenerators discriminatorily high rates for standby, maintenance, and supplemental power; (3)

Although the electricity industry is largely investor-owned, it is highly regulated due to its monopolistic nature and its critical importance to the American public's health, safety, and general welfare.⁹ Administrative controls at federal, state, and local levels affect the planning, construction, operation, and marketing activities of electric utilities. The cogenerator must function within this regulatory framework and attempt to minimize its burdens and maximize its benefits. Any attempts to function outside the regulations would leave the operator without a ready market for surplus power and with little capability of storing it.¹⁰

Commerce is governed by both state and federal regulations, and states frequently implement and enforce federal laws. This is the case with the Public Utilities Regulatory Policies Act (PURPA),¹¹ which governs transactions between the electric industry and cogenerators. PURPA¹² significantly advanced cogeneration development in the United States, spawning a multi-billion dollar industry that greatly exceeded the drafters' expectations.¹³ PURPA, the

applying uneven policies in determining avoided cost; (4) imposing unnecessary and costly interconnection requirements; and (5) denying cogenerators access to transmission facilities. See *The Public Utilities Regulatory Policies Act of 1978 and its Effect on Competition in the Electric Power Industry: Hearings Before the Subcomm. on Energy Conservation and Power of the House Comm. on Energy and Commerce*, 99th Cong., 2d Sess. 7-12 (1986) [hereinafter *House PURPA Report*] (statement of Phillip Van Huffel, President, Industrial CoEnergy Systems and Executive Vice President, Enegrid Investment, Ltd.).

In response, it has been argued that the question of barriers to competition to cogenerators is moot, as there is "no compelling reason to support the contention that competition can now or in the near future guarantee cheaper, more reliable and-or more efficient energy service." *Id.* at 389 (statement of the Illinois Dep't of Energy and Natural Resources).

9. See *infra* notes 16-36 and accompanying text.

10. See Mogk, *supra* note 4, at 135: "The electricity industry in the . . . U.S. is as a practical matter the only supplier to and purchaser of power from the CHP [combined heat and power] operator . . ." See also Lock & Van Kuiken, *Cogeneration and Small Power Production: State Implementation of Section 210 of PURPA*, 3 SOLAR L. REP. 659, 661 (1981).

11. Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of titles 15, 16, 30, 42 and 43 U.S.C.).

12. PURPA was promulgated in 1978 as part of the National Energy Act (NEA). For a summary of the legislative history of the NEA, see H.R. REP. No. 543, 95th Cong., 2d Sess. 3 (1977), reprinted in 1978 U.S. CODE CONG. & ADMIN. NEWS 7673.

13. Cogeneration projects initiated under PURPA now constitute a majority of the new generating capacity in several parts of the country. See *infra* note 205 and accompanying text.

Powerplant and Industrial Fuel Use Act (FUA),¹⁴ and the Clean Air Act Amendments of 1977 (CAA)¹⁵ represent the principal legislation affecting the use and expansion of cogeneration in the United States today.

This Article begins with a short history of the development of the electric utility industry. The discussion then focuses on the three main pieces of legislation a cogenerator will face when entering the electric supply industry: PURPA, the FUA, and the CAA. Although concentrating on PURPA, the Article discusses the benefits and requirements created by all three Acts. Finally, a review of the Detroit, Michigan cogeneration project and the regulatory scheme surrounding its use provides a current example of the impact of the present regulatory framework on cogeneration projects in the United States.

II. UTILITY REGULATORY FRAMEWORK

Since cogenerators must work very closely with utilities, industries or businesses interested in entering the field of cogeneration should be familiar with the present system of utility regulation. This section provides a brief historical review of the development of this regulation, and concludes with an explanation of the present responsibilities of state and federal regulators.

Utilities were allowed to develop as natural monopolies because of a perception that they could produce and distribute energy more efficiently in a non-competitive setting.¹⁶ However, monopolies have generally led to abuses of economic power when unchecked by competition. Accordingly, where government has nurtured mo-

14. Power Plant and Industrial Fuel Use Act of 1978, Pub. L. No. 95-620, 92 Stat. 3289 (codified in scattered sections of titles 5, 15, 16, 42, and 49 U.S.C.). See *infra* notes 245-63 and accompanying text.

15. 42 U.S.C. §§ 7401-76 (1982). See *infra* notes 264-83 and accompanying text.

16. C. PHILLIPS, *THE REGULATION OF PUBLIC UTILITIES: THEORY AND PRACTICE* 5 (2d ed. 1985). See 2 A. KAHN, *THE ECONOMICS OF REGULATIONS: PRINCIPLES AND INSTITUTIONS* 117 (1971). Kahn notes that a natural monopoly exists when an industry exhibits decreasing costs of production as the quantity of production increases. *Id.* at 119. Natural monopolies usually involve firms with substantial fixed and start-up costs. Consequently, the larger the firm, the lower its costs of production and the greater its ability to survive in the marketplace. *Id.* at 118-20. But see W. PRIMEAUX, *DIRECT ELECTRIC UTILITY COMPETITION: THE NATURAL MONOPOLY MYTH* 16-18 (1985) (natural monopoly concept not useful when concluding that utilities should not face competition).

nopolization, it has eventually regulated the industry.¹⁷ The utility industry is no exception.¹⁸

A. *Pre-Commission Regulation*

When public utilities appeared in the late 1800s and early 1900s, states used selective approaches to protect the public interest. These efforts fell into three categories: (1) judicial control; (2) legislative regulation; and (3) franchising. Under the first approach, the courts, adopting a rule of fairness, required businesses that affected the public interest, including utilities, to serve all area customers in an adequate and nondiscriminatory fashion at reasonable rates.¹⁹ In general, this method of regulation was expensive, slow, and inefficient.²⁰ The second method, legislative regulation, used special corporate charters, general incorporation laws, and specific statutes to define a utility's sphere of activity.²¹ However, as the industry grew and the need for greater control increased, the legislative process was unable to meet the challenge.²² Under the third approach, franchise agreements describing the parties' benefits and burdens were negotiated between the utility and the local government.²³ However, even more than legislative enactments, these agreements were no match for the changing times and conditions.²⁴

A need for greater enterprise, flexibility, and continuity in the regulatory process became apparent.²⁵ Independent regulatory commissions (administrative agencies) answered this need, first at the state level, then at the federal level for regional or national matters.

17. Regulation is viewed as both necessary and desirable to insure protection of the public interest. *See* C. PHILLIPS, *supra* note 16, at 3.

18. Electric utilities are allowed to monopolize particular service areas, but in return the utilities must submit to regulation, which substitutes for ordinary market forces. *See* 3 PUB. UTIL. REP. GUIDE at 1 (1983); Note, *supra* note 5, at 153.

19. *See* M. FARRIS & R. SAMPSON, PUBLIC UTILITIES: REGULATION, MANAGEMENT, AND OWNERSHIP 60-61 (1973); C. PHILLIPS, *supra* note 16, at 110.

20. C. PHILLIPS, *supra* note 16, at 111.

21. M. FARRIS & R. SAMPSON, *supra* note 19, at 61-62; C. PHILLIPS, *supra* note 16, at 111-12.

22. M. FARRIS & R. SAMPSON, *supra* note 19, at 62.

23. *Id.* at 62-63; C. PHILLIPS, *supra* note 16, at 112-14.

24. C. PHILLIPS, *supra* note 16, at 113-14. Some of these regulatory methods still exist in some form at state and local levels.

25. *Id.* at 115.

B. State Commissions

At both the state and federal levels, independent²⁶ regulatory commissions continuously supervise the electric utility industry, attempting to protect the interests of the public and enforce the utilities' obligations.²⁷ Commissions are empowered to affirmatively review utility initiatives, but as a matter of practice, their role is largely reactive to utility actions or requests. A commission can, however, initiate corrective measures, such as finding a rate schedule unreasonable and ordering it adjusted.²⁸ Commission decisions are subject to judicial review to determine whether the agency has acted properly and within its prescribed powers. Usually, commissions are granted broad latitude in matters of discretion, and decisions are only overturned if they are arbitrary or capricious.²⁹

States and municipalities have regulated the utility industry from its inception.³⁰ State commissions, called "public service commissions" or "public utility commissions," vary in size from three to ten members, with both appointed and elected members. Commissions generally possess broad authority and have jurisdiction over the telephone, gas, and water industries, as well as the electric power industry.³¹ They have the authority to set retail rates and company performance standards, and to establish rate adjustment mechanisms and service areas.³² The benefits to utilities from

26. 3 PUB. UTIL. REP. GUIDE at 6 (1983). The commissions are independent, in theory, from the other branches of government for four reasons. First, appointments are for definite but staggered terms. Second, no more than a majority of commissioners may come from the same political party. Third, the power to remove commission members is limited. Finally, the procedural features of the commission inhibit executive control. C. PHILLIPS, *supra* note 16, at 132-33. This independent status was aimed at keeping political influence out of the commissions' work and decisions. *Id.* at 133.

27. 4 PUB. UTIL. REP. GUIDE at 1 (1983). The duties of public utilities include: (1) serving all who seek service within the area of operation; (2) rendering service at fair and reasonable rates; (3) serving all qualified customers in a nondiscriminatory manner; and (4) rendering safe, adequate, and satisfactory service. 3 PUB. UTIL. REP. GUIDE at 2 (1983). In return, public utilities have several rights. *See infra* text accompanying note 33.

28. *See* 3 PUB. UTIL. REP. GUIDE at 6-8 (1983).

29. *See* American Paper Inst., Inc. v. America Elec. Power Serv. Corp., 461 U.S. 402, 412 n.7 (1983) (FERC "full-avoided-cost rule must be reviewed solely under the more lenient arbitrary-and-capricious standard . . .").

30. S. BREYER & P. MACAVOY, ENERGY REGULATION BY THE FEDERAL POWER COMMISSION 91 (1974).

31. 4 PUB. UTIL. REP. GUIDE at 7 (1983).

32. *See* S. FENN, AMERICA'S ELECTRIC UTILITIES: UNDER SIEGE AND IN TRANSITION (1984).

state regulation, in turn, are several: (1) the right to a reasonable price for service; (2) the right to reasonable operating conditions; (3) protection from competition; and (4) the use of the state's police power through eminent domain to construct the electricity system.³³

C. Federal Regulation

Although Congress can control virtually every aspect of utility operations, the federal role largely supplements the state commissions.³⁴ Federal regulations date from 1920, when the Federal Power Commission (FPC) was created to administer the Federal Water Power Act.³⁵ The Federal Power Act of 1935 broadened the FPC's power, giving it authority over the interstate transmission and sale of wholesale electricity, but leaving the regulation of retail electric power rates to state commissions.³⁶ The Federal Energy Regulatory Commission (FERC) replaced the FPC in 1977, and retained the FPC's powers over the electricity industry. As with state commissions, the FERC can exercise only specific delegated powers. However, Congress has granted the FERC a broad scope of regulatory authority.

The National Energy Act (NEA) of 1978³⁷ added important cogeneration regulation responsibilities to the FERC. PURPA, one of the NEA's five acts, is most important to the cogenerator and represents an unprecedented federal step into the retail electricity domain of state commissions.

III. PURPA

A. In General

Congress enacted the NEA in order to establish a comprehensive national energy policy. The NEA was designed to improve the conservation and efficient use of the nation's energy resources through the promotion of alternative energy technologies, including

33. 3 PUB. UTIL. REP. GUIDE at 2 (1983).

34. 5 PUB. UTIL. REP. GUIDE at 1 (1983).

35. 41 Stat. 1077 (1920) (codified as amended at 16 U.S.C. §§ 791-825 (1982)). See generally R. BAUM, THE FEDERAL POWER COMMISSION AND STATE UTILITY REGULATION (1942).

36. See Note, *supra* note 5, at 153.

37. The NEA consists of five separate acts. See *infra* notes 39-42 and accompanying text.

cogeneration.³⁸ The NEA is actually five acts, each with the goal of improving energy conservation and fuel usage efficiency. Its five separate acts are: PURPA; the Energy Tax Act (ETA);³⁹ the National Energy Conservation Policy Act (NECPA);⁴⁰ the Powerplant and Industrial Fuel Use Act (FUA)⁴¹ and the National Gas Policy Act (NGPA).⁴²

Of the five acts, only the ETA lacks provisions directed toward cogeneration. PURPA focuses principally on the cogeneration marketplace, while the other three acts address selected obstacles to cogeneration's use. The FUA and the NGPA are aimed at easing industry regulations when more efficient cogeneration systems are employed.⁴³ Similarly, the NGPA provides an exemption for cogenerators from the incremental pricing requirements of the Act.⁴⁴ The NECPA also encourages cogeneration by providing discretionary grants for cogeneration projects attached to schools and hospitals.⁴⁵

PURPA was the centerpiece for cogeneration in the NEA.⁴⁶ It was designed to remove three significant obstacles in the cogen-

38. See *supra* note 12.

39. Pub. L. No. 95-618, 92 Stat. 3174 (1978) (codified as amended in scattered sections of 26 U.S.C.).

40. Pub. L. No. 95-619, 92 Stat. 3026 (1978) (codified as amended in scattered sections of titles 15, 42, and 49 U.S.C.).

41. Pub. L. No. 95-620, 92 Stat. 3289 (codified in scattered sections of titles 5, 15, 16, 42, and 49 U.S.C.).

42. Pub. L. No. 95-621, 92 Stat. 3350 (1978) (codified as amended in scattered sections of titles 15 and 42 U.S.C.).

43. The FUA, for example, originally gave the Secretary of Energy the power to exempt cogenerators from its prohibition against electric utilities burning oil or natural gas as a primary fuel. 42 U.S.C. § 8302(10)(c) (1978). However, this prohibition has been repealed. See *infra* notes 251-54 and accompanying text. Under the FUA, cogenerators continue to be exempt under the FUA from regulations governing large oil or gas-fired projects. See 42 U.S.C.A. §§ 8322(c), 8352(c) (West Supp. 1989). See *infra* notes 255-63 and accompanying text.

44. 15 U.S.C. § 3346(c)(3) (1982). See 45 Fed. Reg. 38,080 (1980).

45. 42 U.S.C. §§ 6371(2)(k), 6371e (1982). One commentator notes that "[s]ince cogeneration projects were only one type of project among many competing for the limited funds available in this program, the chief virtue of this provision probably was that it highlighted a new congressional awareness and approval of cogeneration." Wooster, *supra* note 3, at 718.

46. Congress listed three broad goals in enacting PURPA: (1) conservation of electric energy; (2) increasing the efficient use of utility facilities and resources; and (3) encouraging equitable rates for electric consumers. H.R. CONF. REP. NO. 1750, 95th Cong., 2d Sess. 69, reprinted in 1978 U.S. CODE CONG. & ADMIN. NEWS 7797, 7803. Although most of the controversy surrounding the implemen-

eration marketplace: (1) the refusal of utilities to purchase electricity produced by independent cogenerators; (2) the charging by utilities of discriminatorily high rates for back-up service required by cogenerators;⁴⁷ and (3) the risk that cogenerators would be subjected to inhibiting federal and state utility regulation in providing electricity to utilities.⁴⁸ Congress granted the FERC authority to adopt regulations implementing PURPA.⁴⁹

B. *Constitutionality of PURPA*

PURPA withstood constitutional challenge in *FERC v. Mississippi*,⁵⁰ which confirmed congressional power to enact PURPA under the commerce clause. After Mississippi promulgated regulations implementing PURPA, the state and the Mississippi Public Service Commission sued the FERC, challenging the constitutionality of titles I⁵¹ and III⁵² and section 210⁵³ of PURPA. These sections require state utility commissions to consider the federal standards for both retail electric rates and agreements between utilities and qualifying facilities (QFs). Mississippi argued that these provisions exceeded congressional commerce clause power, and invaded tenth amendment state sovereignty. The Supreme Court upheld the validity of PURPA, and held that the challenged sections did not violate either the commerce clause or the tenth amendment.⁵⁴

tation of PURPA involves setting equitable rates for consumers (see *infra* notes 142-76), studies have also been conducted on whether PURPA has achieved its conservation and efficiency goals. One study noted the "significant net reduction in natural gas, oil, and coal use for electricity production attributable to the presence of QFs [qualifying facilities] in the utility service areas analyzed." Lennon & Meyers, *Net Energy Use Impacts of PURPA Implementation*, 121 PUB. UTIL. FORT., May 12, 1988, at 28, 36. As a cautionary note, this study recommended continued supervision of cogenerators to ensure that PURPA's goals are met in the future. *Id.* at 38.

47. Back-up power is "electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility." 18 C.F.R. § 292.101(a)(9) (1988).

48. 45 Fed. Reg. 12,214-15 (1980).

49. 16 U.S.C. § 824a-3(a) (1982).

50. 456 U.S. 742 (1982).

51. 16 U.S.C. §§ 2601-45 (1982).

52. Retail Policies for Natural Gas Utilities, 15 U.S.C. §§ 3201-11 (1982).

53. 16 U.S.C. § 824a-3 (1982).

54. 456 U.S. at 771.

The Court agreed that Congress had the power under the Commerce Clause to regulate electric utilities in intrastate commerce.⁵⁵ In enacting PURPA, Congress found that the regulated activities of generation, sale, and transmission of electric power "have an immediate effect on interstate commerce."⁵⁶ The Court applied the judicial standard for determining the validity of congressional findings as enunciated in *Hodel v. Indiana*:⁵⁷ "A court may invalidate legislation enacted under the Commerce Clause only if it is clear that . . . there is no reasonable connection between the regulatory means selected and the asserted ends."⁵⁸

The Court indicated that "federal regulation of intrastate power transmission may be proper because of the interstate nature of the generation and supply of electric power."⁵⁹ After reviewing the legislative history of PURPA,⁶⁰ the Court held that limited regulation of both retail sales of electricity and of transactions between QFs and utilities was a rational means of encouraging energy conservation and an efficient use of natural resources.⁶¹

The tenth amendment issue divided the Court. Justice Blackmun, writing for a 5-4 majority, stated that section 210 of PURPA did "nothing more than pre-empt conflicting state enactments in the traditional way."⁶² The majority upheld the section 201 requirement, stating that state commissions should implement federal regulations when resolving disputes between utilities and QFs.⁶³ This form of dispute resolution was traditionally used by the Mississippi Public Service Commission.⁶⁴ The Court emphasized that the federal government has the power to enlist state branches of government to further federal ends.⁶⁵

Finally, the majority held that PURPA did not affect the states in their sovereign capacity or threaten their "separate and inde-

55. *Id.* at 753-58.

56. *Id.* at 755. See 16 U.S.C. § 2601 (1982).

57. 452 U.S. 314 (1981).

58. *Id.* at 323-24.

59. 456 U.S. at 755 (citing *Federal Power Comm'n v. Florida Power & Light Co.*, 404 U.S. 453 (1972)).

60. The legislative history reflects the Congressional finding that the present system of energy production was inefficient. See S. REP. NO. 442, 95th Cong., 1st Sess. 7, 9 (1977); S. REP. NO. 361, 95th Cong., 1st Sess. 32 (1977).

61. 456 U.S. at 758.

62. *Id.* at 759.

63. *Id.* at 760.

64. *Id.*

65. *Id.* at 762 (citing *Testa v. Katt*, 330 U.S. 386, 393 (1947)).

pendent existence.”⁶⁶ Since Congress could clearly “pre-empt the States completely in the regulation of retail sales by electricity and gas utilities and in the regulation of transactions between such utilities and cogenerators,”⁶⁷ PURPA could “condition continued state involvement in a pre-emptible area on the consideration of federal proposals.”⁶⁸

C. FERC Regulations

The FERC regulations implementing PURPA are important to a cogenerator. The regulations directly address three responsibilities of cogenerators and utilities: (1) the cogeneration market (purchases and sales, back-up power, and electric utility regulation); (2) qualifying criteria; and (3) interconnection and wheeling. The regulations pertaining to purchases and sales and to interconnection and wheeling are briefly noted here and discussed more extensively in the state implementation section below.

1. Market Regulation

Congress recognized that in order to grow, cogenerators needed a guaranteed market for cogenerated power. PURPA requires utilities to purchase excess electricity from cogenerators if the purchase rate: is reasonable to the utilities' other electric consumers; is in the public interest; does not discriminate against the cogenerator; and does not exceed the utility's incremental cost of alternative electric energy.⁶⁹ The determination of standards for reasonable rates was left to the FERC, which in turn passed the responsibility to state commissions.⁷⁰ PURPA did not define the

66. *Id.* at 765 (citing *Lane County v. Oregon*, 7 Wall. 71, 76 (1869)).

67. *Id.* at 759.

68. *Id.* at 765. Justices Powell and O'Connor dissented from the tenth amendment holding. Justice Powell argued that PURPA imposed a great burden on the states to adopt certain administrative and judicial functions. *Id.* at 771 (Powell, J. dissenting). He found that PURPA conflicted with the concept of federalism and therefore violated the tenth amendment. *Id.* at 772. Justice O'Connor argued vigorously that PURPA invaded state sovereignty by mandating action by the states, intruded upon state decision-making power, and affected the traditional state function of utility regulation. *Id.* at 779-81 (O'Connor, J., dissenting). These factors led her to conclude that the challenged sections of PURPA were invalid. *Id.* at 797.

69. 16 U.S.C. § 824a-3(b) (1982).

70. One commentator notes that “[a]lthough delegation of [the ratemaking] responsibility to the states permits local conditions to be taken into account, it also effectively sidesteps the necessity of solving at the federal level the difficult rate-setting problems presented by the statute.” Pratt, *supra* note 2, at 499.

pivotal terms "just and reasonable" or "discriminate."⁷¹ The definition of "incremental cost of alternative energy," (otherwise known as "avoided cost")⁷² was broadly described as the cost to the electric utility of the electric energy that, but for the purchase from the cogenerator, would be generated or purchased from another source.⁷³ The FERC did, however, mandate that the states adopt a "full avoided cost" standard,⁷⁴ which requires state commissions to engage in lengthy proceedings in order to satisfy PURPA's mandatory purchase requirement.

PURPA and the implementing regulations require utilities to sell back-up power to cogenerators.⁷⁵ This requirement can be waived if it impairs the utility's ability to render adequate service to its customers or if the requirement places an undue burden on the utility.⁷⁶ PURPA sought to remedy discriminatorily high back-up rates by requiring these rates to be "just and reasonable to the electric consumers of the electric utility and in the public interest," and nondiscriminatory toward cogenerators.⁷⁷ In the context of back-up power, "just and reasonable" rates are defined as rates equal to those paid by traditional electric service users.⁷⁸

The FERC followed PURPA's directive by promulgating rules exempting qualifying cogenerators from both federal and state utility regulations.⁷⁹ This is based on the premise that cogeneration promotes free market competition among electric suppliers. Accordingly, controls designed to check monopolization are not appropriate to cogeneration.

2. *Qualifying Facilities*

Under the FERC regulations, PURPA applies only to qualifying cogeneration facilities (QFs),⁸⁰ which meet minimum oper-

71. *See id.* at n.40.

72. For a complete discussion of the components of avoided cost, see *infra* notes 152-79 and accompanying text.

73. 16 U.S.C. § 824a-3(d) (1982).

74. 45 Fed. Reg. 12,222-23 (1980), codified at 18 CFR 292.304 (a), (b) (1988).

75. 18 C.F.R. § 292.303(a) (1988). *See supra* note 47 for the definition of back-up power.

76. *Id.* § 292.305(b)(2).

77. 16 U.S.C. § 824a-3(c) (1982).

78. *See Pratt, supra* note 2, at 500.

79. Qualifying cogenerators are exempt from regulations of the Federal Power Act, 16 U.S.C. §§ 791a-828c (1982 & Supp. IV 1986), and the Public Utility Holding Company Act, 15 U.S.C. §§ 79-79z-6 (1982). Additional legislation exempts cogenerators from state regulation of utilities. 16 U.S.C. § 824a-3(e) (1982); *see* 18 C.F.R. §§ 292.601-602 (1988).

80. 18 C.F.R. § 292.203(b) (1988).

ating and efficiency standards,⁸¹ and ownership criteria.⁸² The cogenerator must satisfy the QF standard in order to fully access the surplus power marketplace.

Operating and efficiency standards differ for topping-cycle (power first)⁸³ and bottoming-cycle (heat first)⁸⁴ facilities. Topping-cycle systems must have useful yearly thermal energy output of at least five percent of the total energy output.⁸⁵ Efficiency standards apply only if any of the energy output is natural gas or oil and if the installation began on or after March 13, 1980.⁸⁶ Bottoming-cycle facilities have no thermal energy standards and, as with topping-cycle systems, there are no efficiency standards unless natural gas or oil is used.⁸⁷

81. *Id.* § 292.205. "The efficiency standard was imposed to meet the concerns of those who felt that encouraging oil and gas cogeneration was counter to other provisions of the National Energy Act." Wooster, *supra* note 3, at 723.

82. 18 C.F.R. § 292.206. *See infra* notes 88-90 and accompanying text.

83. Topping-cycle facilities are defined as cogenerators "in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy." 18 C.F.R. § 292.202(d) (1988).

84. Bottoming-cycle facilities are defined as cogenerators "in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production." *Id.* § 292.202(e).

85. *Id.* § 292.205(a)(1). This low 5% operating standard has stirred much debate. Critics of the standard argue that it is being abused by cogenerators who enter the market to produce electricity instead of following PURPA's goal of making their own manufacturing process more efficient. These facilities, called "PURPA machines," use only small amounts of steam for industrial or commercial purposes and use the remainder for electricity production. Although PURPA machines do not differ substantially from electric utility power plants, they qualify for the same benefits as those cogenerators that actually achieve meaningful energy conservation. It is argued that because PURPA encourages efficient fuel usage the FERC should not allow all cogenerators to take advantage of the legislation. Only those facilities meeting PURPA's goals should receive qualifying status. *See House PURPA Report, supra* note 8, at 610-12 (statement of Pacific Gas & Electric Co.); Polsky, *Cogeneration Versus Generation*, 115 PUB. UTIL. FORT., May 30, 1985, at 20. *But cf.* Written Testimony of the Nat'l Indep. Energy Producers Before FERC, Docket No. RM87-12-000, Mar. 23, 1987 [hereinafter Written Testimony of NIEP] (operating and efficiency standards are "generally satisfactory." *Id.* at 45-52).

86. 18 C.F.R. § 292.205(a)(2) (1988). The applicable efficiency standard in this case is no less than 42.5% if the thermal energy output is 15% or more, and no less than 45% if it is under 15%. *Id.* § 292.205(a)(2)(A)(B).

87. *Id.* § 292.205(b)(2). If natural gas or oil is used, the plant's efficiency must be at least 45%. *Id.* § 292.205(b)(1).

The ownership criteria is designed to promote the development of cogeneration independent of the utility industry. A QF "may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from the cogeneration facilities . . .)." ⁸⁸ A person is primarily engaged in the sale of electricity "if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company, . . . or any combination thereof" ⁸⁹ The ownership criteria has been alternatively criticized for not sufficiently encouraging utility ownership, and for granting the utilities too much participation in cogeneration projects. ⁹⁰

88. *Id.* § 292.206(a).

89. *Id.* § 292.206(b). The FERC has effectively relaxed the 50% ownership requirement with respect to partnerships. *Ultrapower 3*, 27 F.E.R.C. (P) 61,094 (1984), involved a general partnership consisting of *Ultrapower 3, Inc.* and *Rincon Investing Co.*, a subsidiary of *Ultrapower 3*. *Rincon* was classified as an "electric utility" under the Federal Power Act. Under the terms of a joint venture agreement between the companies, *Rincon's* capital contribution accounted for two-thirds of the partnership's total contributions. However, management positions and any interest in the venture profits or losses was split equally between the parties. The FERC noted its regulations equated "ownership interest" with "equity interest." *Id.* at 61,183. Therefore, the FERC was faced with the issue of how to define equity interest in such a partnership. *Id.*

In the FERC's view, "the entitlement to venture profits, losses, and surplus after return of initial capital contribution, as well as the fact that both partners share equal control of the venture, is dispositive." *Id.* at 61,184. As such, the commission focused on the "stream of benefits" from the venture to determine the partners' equity interest. *Id.*

Since "Rincon's control of the partnership and entitlement to benefits do not exceed 50%," the FERC found that "Rincon has no more than a 50% equity interest in *Ultrapower 3* and that the ownership criteria of section 292.206" was satisfied. *Id.*

Although *Ultrapower 3* specifically dealt with a small power production facility, the same stream of benefits test has been applied to cogeneration facilities. See *Ultrapower, Inc.*, 46 F.E.R.C. (P) 61,380 (1989); *CMS Midland, Inc.*, 38 F.E.R.C. (P) 61, 244 (1987).

90. Critics of the ownership criteria argue:

Section 210 of PURPA, the only provision directly aimed at influencing utility behavior with respect to decentralized power, forces utilities to cooperate with their competitors, at little gain to the utilities. . . . [B]y giving utilities incentives to become active 'partners' with private producers in the decentralized power enterprise, its maximum development will be best assured.

Note, *supra* note 2, at 321, 332.

Proponents of the criteria argue that state commissions have inadequate resources to properly supervise the industry if utilities are allowed to own greater than 50% of the equity interest in a QF. See *House PURPA Report*, *supra* note

3. *Interconnection and Wheeling*

The FERC regulations require utilities to interconnect with QFs for the purchase and sale of power, but utilities are not obligated to wheel electric power from QFs to other utilities or purchasers.⁹¹ Utilities objected to interconnection on the basis of cost, safety, and competition.⁹² The FERC found that the cost of interconnection was the only legitimate problem.⁹³ To alleviate this problem, the FERC ruled that QFs may interconnect if they pay "any interconnection costs which the State regulatory authority . . . or nonregulated utility may assess . . . on a nondiscriminatory basis."⁹⁴

The FERC originally assumed a passive stance on wheeling,⁹⁵ stating that "if a QF agrees, an electrical utility which would otherwise be obligated to purchase energy or capacity may transmit" to another utility; however, transmission costs may not be included in the purchase price.⁹⁶ Independent electrical producers argue that the FERC, in order to assist QFs, should require wheeling,⁹⁷ and establish a procedure for determining equitable wheeling rates.⁹⁸ Such measures, it is argued, would assure adequate access and reasonable rates. Utilities oppose mandatory wheeling, asserting that it would have a detrimental effect on the system's reliability, economic efficiency, and adequacy of electric power supply.⁹⁹

8, at 55, 65-66 (testimony of the Nat'l Ass'n of Regulatory Utility Comm'rs). Additionally, proponents urge that increased utility involvement might adversely affect ratepayers and other QFs. *Id.* at 419 (testimony of Jan Hamrin for the Indep. Energy Producers Ass'n, et al.).

91. 18 C.F.R. § 292.303(c)(2) (1988).

92. "Although the purported basis for this refusal [to interconnect] was to avoid system operating problems, it more likely was a tactical aspect of utility hostility to cogenerators." Pratt, *supra* note 2, at 508 (footnote omitted).

93. 45 Fed. Reg. 12,229-30 (1980).

94. 18 C.F.R. § 292.306(a) (1988).

95. The FERC's position on the rates, terms, and conditions of wheeling has since changed dramatically. The Commission has asserted exclusive and preemptive control of these aspects of interstate wheeling. See *infra* notes 195-97 and accompanying text.

96. 18 C.F.R. § 292.303(d) (1988).

97. Written Testimony of NIEP, *supra* note 85, at 55.

98. *Id.* at 52. See also *House PURPA Report*, *supra* note 8, at 482, 493 (comments of the Nat'l Ass'n of Energy Serv. Cos. (NAESCO)).

99. For a more extensive discussion of the reliability issue, see *infra* note 176.

D. Validity of FERC Regulations

In *American Electric Power Service Corp. v. FERC*,¹⁰⁰ the petitioners challenged the validity of the regulations the FERC promulgated to implement PURPA. Petitioners, three public utilities, specifically challenged four regulations: (1) the FERC's "full avoided cost rule" for utility purchases of QF power;¹⁰¹ (2) the FERC's "simultaneous transaction rule" for metering purchases and sales to and from QFs;¹⁰² (3) the FERC's grant of blanket authority to cogenerators to interconnect with utilities without meeting the requirements of sections 210¹⁰³ and 212¹⁰⁴ of the Federal Power Act;¹⁰⁵ and (4) the FERC's failure to adopt fuel use criteria in determining qualifying facilities.¹⁰⁶

The court of appeals upheld only the simultaneous transaction rule and the fuel use criteria.¹⁰⁷ The simultaneous transaction rule, which the FERC intended to apply only to new facilities, gives an industrial cogenerator the option of selling all of its output to a utility and simultaneously purchasing all of its needs from the same utility.¹⁰⁸ This practice is permitted when a utility needs additional capacity, and one of its customers can build and operate a new cogeneration facility more cheaply than the utility could build and operate its own facility.¹⁰⁹ Petitioners in *American Elec-*

100. 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom.*, *American Paper Inst. v. American Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

101. 18 C.F.R. § 292.304(b)(2) (1988).

102. *Id.* § 292.303(e).

103. 16 U.S.C. § 824i (1982).

104. *Id.* § 824k (1982).

105. 18 C.F.R. § 292.304(b)(4) (1988).

106. *Id.* § 292.204.

107. 675 F.2d at 1245-46.

108. 18 C.F.R. § 292.304(b)(4) (1988).

109. *See* 44 Fed. Reg. 38,870 (1979). The FERC explained that the simultaneous transaction rule was only intended to apply to this situation, as "it would be in everyone's interest for the QF to build the unit." *Id.* However, if the utility's costs in constructing a facility for additional capacity would be lower than the required avoided cost payments to the QF, the FERC felt it would be best for the utility to build the plant itself and supply its own needs. *Id.*

The FERC stated that the simultaneous transaction rule should not apply to existing facilities that already supplied some of their own power needs since allowing industrial cogenerators to sell power at avoided cost and to purchase power at the retail rate would constitute a windfall to the cogenerator. This would not be in the public interest, as it "would drive up the costs of power to the utility's other customers without doing anything to encourage new cogeneration . . ." *Id.* at 38,871.

tric argued first, that allowing the fictional purchase and sale violated section 210(a) of PURPA,¹¹⁰ and second, that the FERC did not adequately explain its decision to employ the fiction.

The court rejected both of these arguments, reasoning that Congress did not intend narrow definitions of "purchase" and "sale" that would treat cogenerators consuming all generated power differently than cogenerators selling excess power.¹¹¹ Noting the reluctance of utilities to purchase electric power from cogenerators or to adopt appropriate rates, the court determined that the FERC should exercise a great deal of deference in this area.¹¹² The court found that the FERC had sufficiently explained and considered the issues, and allowed the simultaneous transaction rule to stand.¹¹³

The court also upheld the lack of fuel use criteria. The petitioners had argued that section 201¹¹⁴ of PURPA required the FERC to include fuel use standards in the regulations. However, after reviewing the wording of the statute, the intent of the Powerplant and Industrial Fuel Use Act, and PURPA's stated goals, the court concluded that the FERC had the discretion to omit fuel use requirements.¹¹⁵

110. 16 U.S.C. § 824a-3(a) (1982).

111. 675 F.2d at 1237-38.

112. *Id.* at 1238.

113. *Id.*

114. 16 U.S.C. § 796(18)(B) (1982) provides in pertinent part: "'Qualifying cogeneration facility' means a cogeneration facility which - (i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule prescribe"

115. 675 F.2d at 1245. Section 201 contains the word "may" instead of "must" in dealing with the creation of fuel use criteria. *Id.* at 1241. The court agreed with the FERC that Congress did not intend to exclude oil and gas-fired cogenerators from QF status. If Congress did intend this exclusion, the statute would have contained such a restriction, as it did for small power producers. *Id.* See 16 U.S.C. § 796(17)(A)(i) (1982).

The lack of fuel use standards was also consistent with the Powerplant and Industrial Fuel Use Act (FUA). 42 U.S.C. §§ 8302(7), (10) (1982). The court reasoned that Congress could not have intended to require fuel use standards for cogenerators under PURPA, since these facilities were already exempt from fuel use criteria under the FUA. 675 F.2d at 1242. See 42 U.S.C. §§ 8322(c), 8522(c) (1982).

The court held that any application of fuel use standards would run counter to PURPA's express purpose to increase the utilities' efficient use of facilities and resources, and that the FERC's consideration of the fuel use issue was reasoned and adequate. 675 F.2d at 1242.

The court struck down the FERC's full avoided cost rule as inconsistent with PURPA's language requiring sales rates for QF power to be "just and reasonable" and "in the public interest."¹¹⁶ The court also vacated the FERC's regulations with respect to interconnection.¹¹⁷ By requiring "any" utility to interconnect with "any" cogenerator, the FERC essentially exempted QFs from procedural and substantive requirements under sections 210¹¹⁸ and 212¹¹⁹ of the Federal Power Act, and also deprived utilities of the Act's safeguards.¹²⁰

The FERC appealed the full avoided cost and interconnection rulings, and the Supreme Court unanimously reversed both lower court holdings.¹²¹ The Court first noted that the court of appeals employed the incorrect standard of review in evaluating the FERC regulations.¹²² The lower court used the "substantial evidence" standard; instead, it should have determined whether the FERC rule was " 'arbitrary, capricious, [or] an abuse of discretion.' "¹²³

Section 210 of PURPA requires utilities to pay QFs a rate that is just and reasonable to the electric utility's consumers, in the public interest, and non-discriminatory.¹²⁴ Since the full avoided cost rule is nondiscriminatory towards QFs, the Court focused only on whether the FERC adequately explained why the full

116. 675 F.2d at 1232. The court stated that Congress clearly distinguished a just and reasonable rate from a rate based on full avoided cost. *Id.* at 1233. Although the FERC might have been justified in choosing this maximum rate, the court held that the Commission must fully justify and explain its rationale in light of the competing interests of cogenerators, electric utility consumers, and the general public. *Id.* at 1236.

117. *Id.* at 1238-41. See 18 C.F.R. § 292.303(c)(1) (1988).

118. 16 U.S.C. §§ 824i(a)(i), (b), (c) (1982).

119. *Id.* § 824k.

120. 675 F.2d at 1239. The FERC argued that strict compliance with these requirements "would impose an undue burden on cogenerators." The court disagreed, holding that the FERC had no authority to grant exemptions from sections 210 and 212 of the Federal Power Act, and that Congress must mandate any changes in procedures. *Id.* at 1240.

121. *American Paper Inst., Inc. v. American Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

122. *Id.* at 412 n.7. The "substantial evidence" standard requires that the agency decision be supported by a substantial factual basis. *Id.*

123. *Id.* at 412 (quoting 5 U.S.C. § 706(2)(A) (1982)). This standard of review is more deferential to the agency's determinations and will invalidate a regulation only if the agency has not adequately considered the relevant factors and has committed "a clear error of judgment." *Id.* at 413 (citing *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402, 416 (1971)).

124. 16 U.S.C. § 824a-3(b) (1982).

avoided cost rule is just and reasonable and in the public interest.¹²⁵ First, the Court rejected the utilities' suggestion that "just and reasonable" be equated with the lowest possible reasonable rate.¹²⁶ After reviewing PURPA's legislative history, the Court determined that since Congress intended to further alternative energy technologies, traditional rate-making concepts should not apply.¹²⁷ Therefore, the FERC could set a rate that provided a significant incentive to cogenerators. This type of rate would benefit the public through the conservation and efficient use of energy resources.¹²⁸

The Court noted that the full avoided cost standard is not totally inflexible. Waivers can be granted,¹²⁹ or QFs and utilities can negotiate a contract at less than full avoided cost.¹³⁰ Since the Court found it reasonable for the FERC to set the maximum rate, it concluded the regulation was not arbitrary and, therefore, was valid.¹³¹

The Court upheld the FERC's interconnection rule, noting that the FERC had the power to require utilities to physically connect with cogenerators, as "[n]o purchase or sale of electricity can be completed without an interconnection between the buyer and the seller."¹³² The utilities argued that PURPA section 210(e)¹³³ required evidentiary hearings by the FERC on a case-by-case basis to determine if interconnection would be required. The Court rejected this argument, reasoning that holding such hearings for every interconnection would "paralyze" the development of cogeneration.¹³⁴ The interconnection rule does not immunize QFs from the requirements of sections 210 and 212 of the Federal Power Act obligating cogenerators to obey an interconnection order.¹³⁵ Instead, the interconnection rule merely requires other parties, namely electric utilities, to interconnect.¹³⁶ The FERC's

125. 461 U.S. at 413-14.

126. *Id.* at 414.

127. *Id.*

128. *Id.* at 415.

129. *Id.* at 416. See 18 C.F.R. § 292.403 (1988).

130. 461 U.S. at 416. See 18 C.F.R. § 292.301(b)(1) (1988).

131. 461 U.S. at 417-18.

132. *Id.* at 418.

133. 16 U.S.C. § 824a-3(e) (1982).

134. 461 U.S. at 421 (citing *Clark v. Uebersee Finanz-Korporation, A.G.*, 332 U.S. 480, 489 (1947) (hearing requirement would "impute to Congress a purpose to paralyze with one hand what it sought to promote with the other").

135. *Id.* at 421-22. See 16 U.S.C. §§ 824i, 824k (1982 and Supp. IV 1986).

136. 461 U.S. at 421-22.

rule was a reasonable and therefore valid interpretation of the statute.¹³⁷

E. State Implementation of PURPA

1. In General

This discussion summarizes the different implementation methods adopted by various states to satisfy the FERC regulations. The FERC allowed the states one year to implement PURPA.¹³⁸

137. *Id.* at 423.

138. 18 C.F.R. § 292.401(a) (1988). Implementation of PURPA was often difficult. Conflicts between utilities, cogenerators, and regulators were common as all parties struggled toward fair and equitable solutions. For example, one participant noted:

State-by-state implementation of PURPA is both a strength and a problem. Implementation of PURPA to achieve the desired results is neither simple nor is it a "one shot process." The regulators, utilities, and intervenors must be very thoughtful and sophisticated in their development of a QF program if it is to be effective. . . . Effective PURPA implementation . . . is no small feat.

House PURPA Report, supra note 8, at 409-10 (statement of Jan Hamrin for the Indep. Energy Producers Ass'n and the Indep. Energy Producers Forum).

Many utilities, hostile to the benefits granted to cogenerators within the existing electric power system, argued against the expanded use of QFs. The utilities emphasized that cogenerators lack any obligation to serve the public, and they stressed the potential negative impacts of this lack of obligation on the utility's ratepayers:

The bottom line is that both the utility and its ratepayers are subjected to greater risks. The performance and persistence of QFs, especially across a wide range of general economic conditions, is not the same as a utility's, nor is it well understood. A QF's obligations to the public are contractual and relatively limited. On the other hand, a utility's obligations are more extensive and established by a totally different body of laws and regulations. If a QF's economics turn sour, the QF can simply stop supplying power and suffer a comparatively limited economic loss. But such an option is not available to the public utility. Thus, as QF power assumes a larger share of total production, ratepayers will be involuntarily assuming more risks as they unwittingly participate in an experimental modification of the traditional electric utility structure and with it the traditional service obligation.

Implementation of the Public Utility Regulatory Policies Act of 1978 Before the Senate Comm. on Energy and Natural Resources, 99th Cong., 2d Sess. 108, 140-41 (1986) [hereinafter *Senate PURPA Hearings*] (statement of Michael R. Peevey, Executive Vice President, Southern Calif. Edison Co.).

Another problem related to the QFs' lack of obligation to serve is the possibility that QFs can increase their profitability by gauging production and

The states had three major responsibilities: (1) to establish rates for the purchase of electric power from QFs,¹³⁹ for the sale of electricity to QFs,¹⁴⁰ and for the sale of supplementary, back-up, maintenance, and interruptible power from utilities to QFs;¹⁴¹ (2) to maintain interconnection conditions, including required operational standards and the costs to QFs;¹⁴² and (3) to satisfy data filing requirements that allowed potential QFs to determine the potential avoided cost rate likely paid by utilities.¹⁴³ State commissions could: (1) issue their own regulations pursuant to the FERC guidelines; (2) resolve conflicts between utilities and QFs; or (3) take whatever action was reasonably necessary.¹⁴⁴

2. Purchase of QF Power

To encourage the development of cogeneration, the FERC set the rate for utility purchases of QF power at the full avoided cost to the utility. However, individual states can set purchase rates below full avoided cost if the lower rate would be just and reasonable, in the public interest, and nondiscriminatory toward

sales to utilities based on certain high demand load periods. One utility executive stated: "Allowing cogenerators to serve selective 'premium' loads would result in higher costs for the remaining retail and residential customers, who are the very people that traditional public utility regulation protects." *Id.* at 50 (statement of D.E. Simmons, Group Vice President - Power Operations, Houston Lighting & Power Co).

Utilities also disagree with the notion that the addition of cogenerators to the electric power market will benefit consumers by stimulating greater competition in the supply of power:

What PURPA does is create a two-tiered market wherein a privileged set of participants (i.e., QFs) are given the opportunity of earning an unregulated return by guaranteeing them a purchaser for the sale of their output at an administratively determined price. In effect, we have "deregulated" a small set of sellers by imposing a new set of regulatory burdens on the buyer. It is difficult to conceptualize this arrangement as constituting a "competitive market" or having anything to do with the economist's notion of competition. . . . "Yardstick competition" is a questionable concept in theory and is totally irrelevant in practice unless all market participants are operating on a level playing field. This is certainly not the case under the PURPA model.

Id. at 46 (statement of D.E. Simmons).

139. See 18 C.F.R. § 292.304(a) (1988).

140. *Id.* § 292.305(a).

141. *Id.* § 292.305(b).

142. *Id.* §§ 292.306, .308.

143. *Id.* §§ 292.302(b)(1-3).

144. *Id.* § 292.401(a).

QFs.¹⁴⁵ A full avoided cost standard is also unnecessary when a QF and a utility mutually agree to a different rate.¹⁴⁶ Additionally, the FERC has allowed the waiver of purchase obligations when the goals of PURPA would not be compromised.¹⁴⁷

Jurisdictions have split on the question of whether a state can require utilities to pay more than the avoided cost rate for its mandatory purchases.¹⁴⁸ New York, for example, has approved a minimum rate for utility purchases that applies even when the utility's avoided cost falls below that minimum.¹⁴⁹ Similarly, Ore-

145. *Id.* § 292.304(3).

146. *Id.* § 292.301(b). State regulatory commissions can also secure waivers from the FERC full avoided cost standard. *See id.* § 292.403.

147. *Oglethorpe Power Corp. et. al.*, 32 F.E.R.C. (P) 61,103 (1985), *reh'g granted in part*, 35 F.E.R.C. (P) 61,069 (1986), *aff'd sub nom.*, *Greensboro Lumber Co. v. FERC*, 825 F.2d 518 (D.C. Cir. 1987).

In *Oglethorpe*, a rural electric cooperative in Georgia sold power at wholesale to its member co-ops, which distributed the electricity at retail. The individual retail co-ops (EMCs) wanted to avoid purchasing cogenerated power from QFs by allowing the wholesale generation and transmission facility (*Oglethorpe*) to purchase all the QF power. The Commission allowed the waiver of the purchase obligation by the individual retail co-ops. It was much more economical for *Oglethorpe* to coordinate all of the purchases than to burden each retailer with the costs of providing an administrative staff to handle the transactions. 32 F.E.R.C. (P) 61,103, at 61,285-86. The goals of PURPA were not compromised under such an arrangement, since QFs were still guaranteed a market for their power. *Id.* at 61,285. Therefore, the waiver of the purchase obligation was granted. *Id.* at 61,287.

On rehearing, a waiver of the sale obligation was also granted. 35 F.E.R.C. (P) 61,069, at 61,137. *Oglethorpe* was allowed to waive its obligation to sell power to QFs, on the condition that the EMCs agreed to sell to the QFs all their required back-up and maintenance power. Since this guaranteed that QFs could obtain back-up service, the waiver was granted. *Id.* at 61,138.

The United States Court of Appeals upheld the waivers of both obligations, deferring to the FERC's reasonable interpretations of its regulations. 825 F.2d at 523.

148. The Supreme Court has refused to resolve this issue on the basis of a lack of a substantial federal question. *Consolidated Edison Co. v. Public Serv. Comm'n*, 63 N.Y.2d 424, 472 N.E.2d 981, 483 N.Y.S.2d 153, (1983), *cert. denied*, 470 U.S. 1075 (1985).

149. In approving a purchase rate that exceeds avoided cost in some instances, the New York Appellate Division court reversed a lower court decision invalidating the state's six cent per kilowatt hour minimum purchase rate. *Consolidated Edison Co. v. Public Serv. Comm'n* 98 A.D.2d 377, 471 N.Y.S.2d 684 (1983). The lower court had found the rate invalid for three reasons. First, the court reasoned that PURPA and the Federal Power Act preempted the area; therefore, the FERC had exclusive rate-setting jurisdiction. *Id.* at 381-84, 471 N.Y.S.2d at 688-90. Second, it felt that there was not a proper consideration of

gon has set a purchase rate in excess of avoided cost.¹⁵⁰ Kansas, on the other hand, has held that utility purchase rates may not exceed full avoided cost.¹⁵¹

Determination of the actual avoided cost is based on several factors, including the QF's power availability during peak periods, the QF's reliability, the ability of the QF and utility to schedule outages, and the existence of a legally enforceable obligation to provide power.¹⁵² The FERC has indicated it would approve most methods for calculating purchase rates, as long as they reasonably account for the utilities' avoided cost and still provide an incentive for cogeneration.¹⁵³ Some states have adopted rates proposed by individual utilities, while others have promulgated standards to determine avoided cost.¹⁵⁴

Two components comprise avoided cost: energy and capacity. The energy component or "energy credit" reflects the utility's fuel costs and the associated operational and maintenance costs avoided

the rate savings to the consumers. *Id.* at 383, 471 N.Y.S.2d at 689. Finally, the court relied on the legislative history, which stated that avoided cost was to be the upper limit for purchase rates. *Id.*

New York's highest court reversed, finding "no direct conflict" between PURPA's avoided cost purchase rate and the state commission's higher rate. 63 N.Y.2d 424, 435, 472 N.E.2d 981, 985, 483 N.Y.S.2d 153, 157 (1984). The state and federal laws were viewed as complementary, allowing the states to provide added incentives to cogeneration by setting higher rates. 63 N.Y.2d at 435 n.8, 472 N.E.2d at 985 n.8, 483 N.Y.S.2d at 157 n.8. (citing 45 Fed. Reg. 12,221 (1980)). The court also stated that the effects of such a rate on consumers were balanced by the more important purpose of encouraging cogeneration. 63 N.Y.2d at 437, 472 N.E.2d at 986-87, 483 N.Y.S.2d at 157. The court noted that the upper limit language relied on by the lower court applied only to one section of PURPA, and reasoned that this restriction implied that states were free to set their own requirements to encourage cogeneration. 63 N.Y.2d at 435, 472 N.E.2d at 985, 483 N.Y.S.2d at 157.

150. See Hagler, *Utility Purchases of Decentralized Power: The PURPA Scheme*, 5 STAN. ENVTL. L.J. 154, 163 (1983).

151. *Kansas City Power & Light Co. v. Kansas Corp. Comm'n*, 234 Kan. 1052, 1058, 676 P.2d 764, 768 (1984). The Kansas Supreme Court reasoned that the federal government had preempted this area. Since avoided cost is a maximum rate of purchase under the federal regulations, the state may not require rates in excess of this maximum absent a waiver or other contractual agreement. *Id.* at 1054-57, 676 P.2d at 765-68.

152. 18 C.F.R. § 292.304(e) (1988).

153. 45 Fed. Reg. 12,222 (1980).

154. See Charo, Stearns & Mallory, *Alternative Energy Power Production: The Impact of the Public Utility Regulatory Policy Act*, 11 COLUM. J. ENVTL. L. 447, 463 (1986) [hereinafter Charo]; Wooster, *supra* note 3, at 737.

by purchasing QF power.¹⁵⁵ The capacity component or "capacity credit" measures the fixed capital cost of building a new power plant that the utility avoids by purchasing QF power.¹⁵⁶

a. The Energy Credit

Since the states acted independently, several major approaches for determining the energy credit have emerged.¹⁵⁷ The "component" or "peaker" method uses detailed models to compute the amount of energy required to produce a certain unit of electricity and the fuel, maintenance, and operational costs associated with that unit.¹⁵⁸ Expected QF power is factored into the model, resulting in avoided energy cost estimates which can be differentiated according to time and cost.¹⁵⁹ The advantage of the component method is its ability to time-differentiate specific components of avoided cost rather than arbitrarily choosing a representative proxy unit.¹⁶⁰ However, the method has been criticized for using models that are difficult to verify, and for not adequately reflecting long-run avoided costs.¹⁶¹

Under the "differential revenue requirements" method, estimates of a utility's generating costs with and without an amount of QF operating capacity are calculated over a number of years.¹⁶² The result is a lump sum of avoided cost that can be divided among energy and capacity costs.¹⁶³ Critics of this method note

155. EDISON ELECTRIC INSTITUTE, BACKGROUND PURPA: HOW ARE AVOIDED COST PAYMENTS CALCULATED? (1987).

156. *Id.*

157. Each approach has a number of variations. See Parmesano, *Avoided Cost Payments to Qualifying Facilities: Debate Goes On*, 120 PUB. UTIL. FORT., Sept. 17, 1987, at 34, 35-37.

158. *Id.* at 35; Wooster, *supra* note 3, at 737-38. Under a variation of the component method, the "incremental heat rate" approach, a significant variable is whether the projected cost or the historical average fuel cost is used. Wooster, *supra* note 3, at 739. Wooster notes that Connecticut's use of the historical average fuel cost results in a lower fuel credit than one calculated by California's use of the projected estimated cost of fuel resources. *Id.* Another variable in systems that cannot differentiate specific blocks of energy is determining which incremental block should be used for calculations—the last incremental block of energy or the next projected incremental block. *Id.* at 738-39.

159. Parmesano, *supra* note 157, at 35.

160. *Id.*

161. *Id.* at 36. Parmesano concludes that the component method is the best way to determine avoided cost. *Id.* at 36-38.

162. *Id.* at 37.

163. *Id.*

that it produces costs that cannot be easily time- and cost-differentiated for specific periods.¹⁶⁴

A third approach, the "proxy system," uses the energy component of power purchased from a pool of cooperating utilities or from another single resource as a proxy for the energy component.¹⁶⁵ The approach has the advantage of simplicity, as a previously determined figure can be applied to transactions between the QF and the utility.¹⁶⁶ The approach's disadvantage is that "while lower cost cogenerators are brought on line first, an average price between low cost and high cost cogenerators is charged, resulting in savings that are split among pool members."¹⁶⁷ Therefore, applying this middle ground rate might not truly reflect the actual avoided energy component of purchasing cogenerated power.¹⁶⁸

b. The Capacity Credit

A capacity credit is appropriate only when a utility needs capacity. The FERC has recently determined that only thirteen states still have capacity needs and must provide capacity credits.¹⁶⁹

164. *Id.*

[A]ll the parameters of a particular utility system which have been captured in the dispatch model can be taken into account in computing avoided costs. . . . This advantage is somewhat illusory, however, since the detailed output from a dispatch model is all dependent on the basic parameters input to the model. . . . Since a utility's 20- to 30-year resource plan typically contains speculative elements, the revenues required to finance such a plan are speculative.

Yokell & Marcus, *Rate Making for Sales of Power to Electric Utilities*, 114 PUB. UTIL. FORT., Aug. 2, 1984 at 21, 23.

165. Wooster, *supra* note 3, at 740, notes that Iowa and New Jersey use this system. This method has also been adopted in some parts of Michigan. See *In re Midland Cogeneration Venture Limited Partnership*, Mich. Pub. Serv. Comm'n Case No. U-8871, (Jan. 31, 1989) at 48 (on file at *The Wayne Law Review*).

166. Yokell & Marcus, *supra* note 164, at 23.

167. Parmesano, *supra* note 157, at 38; Wooster, *supra* note 3, at 740-41.

168. For example, utilities that purchased power from a pool argued to the Connecticut commission that "their ratepayers would lose the savings that these purchases permitted if the utilities were to forfeit this cheaper pool power and pay avoided cost . . ." The state commission responded by permitting a 5% reduction in the energy component paid by the utilities to reflect the pool savings share. Wooster, *supra* note 3, at 741.

169. Notice of Proposed Rulemaking, Administrative Determination of Full Avoided Costs, Sales to Qualifying Facilities, and Interconnection Facilities, 53 Fed. Reg. 9331 (FERC proposed Mar. 16, 1988) (1989) [hereinafter *Avoided*

States use several approaches to calculate capacity credits. The most common is the "unit specified" approach, under which the state commission determines the conceptual cost of a new generating unit.¹⁷⁰ This method only partially accounts for system-wide savings that result from the QF's available power.¹⁷¹ The "differential revenue requirements" method is more accurate.¹⁷² Under this approach, an optimum generating development plan is formed, which determines the difference between the capital cost of optimum capacity expansion with and without QFs. This difference becomes the avoided capacity cost.¹⁷³ The disadvantage of this approach is the difficulty of using and verifying the complex model formulated to calculate the capital costs.¹⁷⁴

States offering capacity credits make payment conditional upon the QF satisfying certain requirements, including: (1) entering into firm contracts with utilities for delivering fixed capacity;¹⁷⁵ (2)

Cost NOPR]. Since PURPA has fostered an unprecedented boom in cogeneration, many utilities are being overwhelmed by excess capacity. "We have managed to become so awash with excess qualifying facility capacity that, if electricity were water, the Pacific Ocean would now be lapping at the Sierra Nevada Mountains." *Remarkable Remarks*, 120 PUB. UTIL. FORT., Dec. 10, 1987, at 9 (quoting Michael R. Peevey, Executive Vice President, Southern California Edison Co.). The NOPRs recently released by the FERC stipulate that capacity credits need not be paid by utilities where capacity is not needed. See *infra* note 210 and accompanying text.

170. Wooster, *supra* note 3, at 746.

171. *Id.* at 748.

172. *Id.* Both Texas and Maine have employed variations of this approach.

173. Charo, *supra* note 154, at 466.

174. See *supra* note 164.

175. The propriety of long-term firm contract prices has recently been debated between utilities and cogenerators. One study called long term contracts with no adjustment mechanisms "the greatest problem to date," because utility customers are punished for past forecasts that cannot be corrected or adjusted to meet present economic realities. *Senate PURPA Hearings*, *supra* note 138, at 283 (1986 report by Hagler, Bailly & Co. prepared for the United States Dept. of Energy).

In response, it has been argued that such long-term contracts are the only means of assuring the promotion of cogeneration by QFs. QFs must have some stability before going ahead with energy production. *Id.* at 294-95 (statement of Jan Hamrin, Executive Director, Indep. Energy Producers Ass'n and Chief Executive Officer, Indep. Energy Producers Forum).

Utilities have attempted to attack such long-term contracts on several different grounds, usually challenging the contract when the market price for energy falls far below the contract price. See Pestle & Butler, *State Legislation Can Help Waste-to-Energy Projects*, 3 SOLID WASTE & POWER, Apr. 1989, at 26. The utilities' attacks include: (1) the direct assertion by the state commission of the

meeting reliability standards for capacity;¹⁷⁶ (3) meeting minimum

authority to invalidate contract prices it finds unacceptable; (2) the limitation of recovery to market price on the basis of the commission's general authority to allow utilities to recover only 'prudently incurred costs'; and (3) the imposition of a duty to renegotiate. *Id.* at 32.

Recently, "anti-cogeneration" rate contracts have been used to discourage the development of cogeneration facilities. These contracts offer major customers lower rates in exchange for an agreement by the customer not to construct or install cogeneration equipment during the contract term. See Norris, *Cogeneration and Small Power Production: Recent Regulatory Developments*, 119 PUB. UTIL. FORT., June 25, 1987, at 47; Radford, *Competition Heats Up After Repeal of Fuel Use Restrictions for Cogeneration*, 120 PUB. UTIL. FORT., Aug. 20, 1987, at 4. For example, the California Public Utilities Commission has approved a number of anti-cogeneration contracts to avoid the uneconomic bypass of its system. Pacific Gas & Electric Co., Resolution E-3017 (Cal. P.U.C. Jan. 28, 1987). The Commission reasoned that such agreements would provide electric power at the same cost as cogenerated power, but would avoid the risks of cogeneration. *Id.* Customers would also benefit by not having to pay the added fixed costs arising from customers who developed cogeneration facilities leaving the system. *Id.*

Similarly, the Arkansas Public Service Commission approved an anti-cogeneration rate contract in which the customer agreed to delay plans to build a qualifying facility. The customer also provided the utility (with a five-year option) its own or jointly owned cogeneration facility at a site close to the customer. Re Arkansas Power and Light Co., 83 PUR4th 12 (Ark. P.S.C. 1987). The Arkansas Commission reasoned that the loss of a major customer would increase costs to other ratepayers, and the use of any cogenerated output would be unnecessary excess capacity. *Id.* at 14-15.

The approval of these contracts is in direct conflict with the purposes behind implementation of PURPA and its goals. It will be interesting to see the FERC's reaction to such contracts.

176. The utility industry raises unreliability as a principal argument against QFs. For example, the utilities point out that under adverse weather conditions QFs go off line and do not immediately return, thereby changing load flow. *Senate PURPA Hearings, supra* note 138, at 58, 64 (testimony of Logan Lanham, Sr. Vice President of Pub. Affairs, Idaho Power Co.). QFs also detrimentally affect reliability by upsetting schedules. *Id.* at 137 (statement of Michael R. Peevey, Executive Vice President, Southern California Edison Co.).

Cogenerators counter that reliability problems do not exist. For example, the Electricity Consumers Resource Council (ELCON) has argued that QFs may actually increase reliability because: (1) industrial cogenerators must be more reliable in order to insure continuity of the manufacturing process; (2) since cogeneration facilities are much smaller than utilities, outages affect only a small percentage of generating capacity; (3) cogenerators provide efficient reactive power close to the utility's system loads; and (4) industrial cogenerators can provide back-up power in times of emergency. *Id.* at 702, 719-20 (statement of ELCON). A public utilities commissioner noted that "[p]roblems with traditional [generating] sources such as cost overruns, poor plant performance, and the resulting fallout have made qualifying facilities very attractive as a way to meet new

capacity requirements; and (4) requiring peak hour production for full capacity payment.¹⁷⁷

The projected need for capacity over the short and long term is a critical issue. Capacity needs rise or fall depending upon a utility's capital investment program, plant life, and market conditions. Credits can be divided into short- and long-term rates,¹⁷⁸ depending on when capacity is needed, or averaged over the life of the contract.¹⁷⁹

3. *Sale of Power to Qualifying Facilities (QFs)*

Rates for power sold to QFs must adhere to the FERC guidelines that require the rates to be just and reasonable, in the public interest, and nondiscriminatory to QFs.¹⁸⁰ In setting sale rates, some states treat QFs like other customers with similar load characteristics, and require both to pay the same retail rate. Other states view QFs as constantly buying electricity from the utility under simultaneous buy and sell transactions.¹⁸¹ Under this view, when an outage at a QF causes utility purchases to fall, utility sales to the QF remain constant. Therefore, rates for back-up and

demands." *Remarkable Remarks*, 120 PUB. UTIL. FORT., Dec. 10, 1987, at 9 (quoting Stanley Hulett, President of the California Public Utilities Commission). See also *Senate PURPA Hearings*, *supra* note 138, at 304-05 (testimony of Jan Hamrin, Executive Director Indep. Energy Producers Ass'n and Chief Executive Officer, Indep. Energy Producers Forum).

177. Wooster, *supra* note 3, at 751-52.

178. Dividing rates into short- and long-term components provides a fairer measure of avoided capacity costs. Requiring a utility to pay capacity credits where no capacity is needed forces the utility, and ultimately the consumer, to pay for unnecessary capacity. See Howe, *Cogeneration Rates: The Present and the Future of Full Avoided Costs*, 113 PUB. UTIL. FORT., May 10, 1984, at 55, 56-57.

179. Levelized or average rates seek to remedy the situation in which a utility needs capacity only during the first part of a long-term contract. The rates are averaged and paid during the entire contract period, whether or not the capacity costs actually exist. Howe, *supra* note 178, at 57. Such rates raise the question of who should pay for future avoided costs — current consumers, or only future consumers through a two-tier system. States have reached both conclusions. For example, Washington held that only future ratepayers should pay for future capacity costs. *Washington Utils. & Transp. Comm'n v. Washington Water Power Co.*, 56 PUR4th 615, 623-26 (1983). Idaho, on the other hand, allowed the payment of future avoided cost by present ratepayers in light of the cogeneration benefits to all ratepayers. Idaho Public Utilities Comm'n Order No. 18744, Mar. 21, 1984.

180. 18 C.F.R. § 292.305(a) (1988).

181. See *supra* notes 108-09 and accompanying text.

supplementary power are unnecessary because the QFs are constantly purchasing at the same retail rate.¹⁸² A third approach includes special rates for back-up and supplementary power service to cover the power the QF normally produces itself. New York, for example, placed special qualifications on when back-up power could be obtained, and added transmission, penalty, and fixed cost charges into back-up rate calculations.¹⁸³ New York also set rates for supplementary power that included transmission and distribution costs.¹⁸⁴ In contrast, New Jersey adopted an approach more favorable to QFs by eliminating additional charges if maintenance was scheduled at the utility's convenience.¹⁸⁵

Some controversy exists as to whether third party-financed cogeneration facilities qualify as QFs in order to receive back-up power from utilities. Recently, the FERC sustained back-up service guarantees for such facilities.¹⁸⁶

182. See Wooster, *supra* note 3, at 753-54 (California and Idaho Commissions express this view).

183. 48 PUR4th at 754-55. See *Re Consolidated Edison Co.* 48 PUR4th 94, 114-20 (N.Y.P.S.C. 1982).

184. *Id.* at 123.

185. Wooster, *supra* note 3, at 755.

186. In *Alcon (Puerto Rico) Inc.*, 32 F.E.R.C. (P) 61,247 (1985), *order on reh'g*, 38 F.E.R.C. (P) 61,042 (1987), the FERC addressed the question of whether PURPA's back-up power guarantees applied to a manufacturing plant that leased the cogeneration equipment used in its plant and had no actual ownership interest in the equipment. Alcon owned a pharmaceutical plant in Puerto Rico and purchased electricity from the Puerto Rico Electric Power Authority (PREPA). Since steam was also used in the manufacturing plant, Alcon decided that an industrial cogeneration system would reduce its energy costs. Alcon entered into an agreement with O'Brien Energy Products whereby O'Brien would engineer, procure, install, and operate a cogeneration system on Alcon's property.

The lease agreement allowed Alcon, after five years, to extend the lease, purchase the equipment, or have O'Brien remove the facility. The agreement was structured as a lease because of tax and financial considerations. When Alcon filed for certification as a QF under the FERC regulations, the PREPA argued Alcon should be denied certification because O'Brien was the actual owner and operator of the cogenerator. Furthermore, if O'Brien were the owner and therefore entitled to back-up power from the PREPA, any resale of the back-up power to Alcon would violate the ownership requirement.

The FERC allowed Alcon's certification, but denied its rights to back-up power. 32 F.E.R.C. (P) 61,247, at 61,579. The Commission reasoned that Alcon could not be an owner of the facility, and therefore, it was not entitled to back-up power. *Id.* Language in the FERC regulations distinguishes energy-producing facilities and energy-consuming facilities. Cogeneration facilities were defined as energy-producing facilities. Since Alcon merely consumed energy, while O'Brien

4. *Interconnection and Wheeling*

Interconnection is crucial to cogenerators because it relates directly to the QFs' ability to purchase and sell electric power.¹⁸⁷ States have taken a variety of approaches in assessing interconnection costs. Some states, including Michigan, adopt the FERC rule, flatly stating that QFs must pay the interconnection costs.¹⁸⁸

owned the production mechanisms, Alcon could not be a QF entitled to back-up power. *Id.* at 61,577-78.

Commissioner Stalon's dissent criticized the majority's narrow view of qualifying facilities. He argued that the consuming/producing distinction was not supported in the legislative history and that all the facts pointed to this arrangement as a typical unified cogeneration facility. *Id.* at 61,581-83. Stalon also warned of the consequences if third party-financed cogenerators could not obtain back-up power, noting that without back-up power, these facilities would not be built, thereby frustrating PURPA's intent to encourage cogeneration. *Id.* at 61,581-84.

Commentators echoed Stalon's dissent and criticized the Commission's decision because it placed a substantial obstacle in the path of industrial cogenerators. See Greenberg, *The ALCON Decision: Disincentive to Cogeneration*, 7 ENERGY L.J. 101, 107-09 (1986); Nowak, *FERC's Alcon Decision May Hinder Cogeneration*, 8 LEGAL TIMES, Sept. 30, 1985, at 10, 12-13.

In a 1987 rehearing, the FERC adopted Commissioner Stalon's dissent, reversed its earlier decision, and ruled that Alcon was entitled to back-up power. 38 F.E.R.C. (P) 61,042 (1987). Although conceding that PURPA and the regulation could be read to exclude Alcon from the definition of an owner, the Commission decided that the consequences of such an interpretation would be too harsh. *Id.* at 61,119. The Commission found other language in the regulations supporting the argument that consuming facilities are entitled to back-up power and held that the right to back-up power extended to both producing and consuming facilities, irrespective of whether both facilities have the same owner. The FERC also noted the prior decision's detrimental effect on third party financing arrangements. *Id.* at 61,120.

187. In this regard the FERC noted:

The availability and cost of interconnections are vital economic considerations for a QF. Interconnection requirements and associated fees can discourage or over-encourage QFs as well as impose costs on a utility's ratepayers and stockholders. If a QF cannot achieve interconnection with the local utility, or can only do so at excessive expense, its incentive to produce power will be greatly diminished. Alternatively, if a utility is not fully compensated for all costs of interconnection, or if the technical quality of the interconnection is insufficient, ratepayers or stockholders will incur costs that they would not have incurred had the utility generated its own power or purchased power from another wholesale source. Both situations result in inefficiencies and are at odds with the objectives of PURPA.

Avoided Cost NOPR, *supra* note 169, at 85-86. See also Lock & Van Kuiken, *supra* note 10, at 682; Wooster, *supra* note 3, at 756.

188. Re Cogeneration and Small Power Production, 48 PUR4th 465, 473 (Mich. P.S.C. 1982).

Others have adopted more detailed procedures. New York specifically requires QFs to pay the cost of delivering power to utilities. This cost includes a metering charge, a carrying charge covering taxes, operation, maintenance, and first time costs, and the cost of feasibility studies.¹⁸⁹ Massachusetts requires utilities to make initial inspections of QF sites and to provide QFs with estimated interconnection costs.¹⁹⁰

Most states allow the purchasing utility to determine the safety and reliability aspects of interconnection.¹⁹¹ Alaska, however, has found that allowing utilities to set individual safety standards might be detrimental to QFs and ordered the promulgation of uniform rules.¹⁹²

Many state commissions have permitted financing schemes for the payment of interconnection costs, with amortization periods ranging from one to five years.¹⁹³ For example, Florida has required the posting of surety bonds if the QF is making installment payments to the utility.¹⁹⁴

In 1984, the FERC asserted exclusive and preemptive jurisdiction over rates for interstate wheeling of electric power.¹⁹⁵ Recently,

189. Re Consolidated Edison Co. of New York, 48 PUR4th 94, 140-44 (N.Y.P.S.C. 1982).

190. Re Sales of Electricity by Small Power Producers and Cogenerators, 77 PUR4th 479, 486 (Mass. D.P.U. 1986).

191. Wooster, *supra* note 3, at 755. New York has adopted this procedure. See 48 PUR4th at 144.

192. Re Cogeneration and Small Power Production, 57 PUR4th 731 (abstract citing Alaska Pub. Util. Comm'n Order No. 4 (June 23, 1982)).

193. Lock & Van Kuiken, *supra* note 10, at 683.

194. Re Load Forecasts, Generation Expansion Plans, and Cogeneration Prices for Peninsular Florida's Electric Utilities, 89 PUR4th 408, 409-10 (Fla. P.S.C. 1988). The Florida Public Service Commission gave several reasons for requiring surety bonds. First, a security interest agreement would give secured creditor status to the utility and enhance its chance of reimbursement in case of default. Second, flexibility to address various risks was assured since no specific type of surety was required. Finally, this small obligation would not detrimentally affect cogeneration. *Id.*

195. Florida Power & Light Co. and Florida Pub. Serv. Comm'n, 29 F.E.R.C. (P) 61,140 at 61,291-92 (1984). The FERC found such authority under part II of the Federal Power Act (FPA). Under section 201(b) of the FPA, (16 U.S.C. § 824(b)), the FERC has the ability to regulate transmission of energy in interstate commerce. Under sections 205 and 206 (16 U.S.C. §§ 824d, 824e), the Commission must determine the reasonableness and justness of utility transmission rates. *Id.* at 61,291. The FERC noted that these provisions of the FPA had consistently been read to provide the FERC jurisdiction when the system is interconnected within the state but has out of state connections. *Id.* at 61,291-

the FERC extended its authority and largely preempted the entire field of wheeling, including the regulation of the rates, terms, and conditions of such transmission.¹⁹⁶ This decision has been criticized as potentially hindering cogenerators' ability to obtain necessary wheeling.¹⁹⁷

States have adopted several different approaches to wheeling. Some states require it, while others allow it on a voluntary basis. Massachusetts amended its regulations to require utilities to wheel QF-produced power.¹⁹⁸ The QF must pay the cost of upgrading a utility's transmission facilities if the upgrading is necessary to provide the wheeling services.¹⁹⁹ Similarly, Florida requires utilities to wheel electric power produced by QFs to other utilities upon request.²⁰⁰ Florida also requires the QFs to pay any costs incurred by the utility in wheeling.²⁰¹ Connecticut statutorily requires electric

92 (citing *Florida Power Comm'n v. Florida Power & Light Co.*, 404 U.S. 453 (1972); *Florida Power Comm'n v. Southern Cal. Edison Co.*, 376 U.S. 205 (1964)). Because all the Florida utilities involved were integrated within an interstate power grid, the FERC had exclusive jurisdiction to set transmission rates for cogenerated power. *Id.* at 61,288, 61,291-92.

196. *Florida Power & Light Co.*, 40 F.E.R.C. (P) 61,045, at 61,116 (1987). Although the FERC had previously declared its authority over interstate transmission rates, *see supra* note 195, the Florida Public Service Commission issued new rules three years later asserting state jurisdiction over the terms and conditions of interstate wheeling. *Id.* at (P) 61,116. The Florida Power & Light Company challenged the new state rule, alleging that the FERC had exclusive jurisdiction over the terms and conditions of interstate wheeling in addition to its exclusive ratesetting authority.

The FERC agreed with Florida Power & Light, holding that it had exclusive and preemptive jurisdiction over interstate wheeling. *Id.* at 61,120-21. The FERC gave two reasons to support this ruling. First, sections 205(a) and 205(c) of the Federal Power Act, 16 U.S.C. §§ 824d(a), (c), had consistently been interpreted as upholding the FERC's jurisdiction over the terms and conditions of interstate wheeling. *Id.* at 61,120 (citing *Kentucky Utilities Co. v. FERC*, 789 F.2d 1210, 1211 (6th Cir. 1986); *City of Cleveland, Ohio v. FERC*, 773 F.2d 1368, 1370 (D.C. Cir. 1985)). Second, the Commission's implementing regulations, 18 C.F.R. § 35.2(b), also evidenced the FERC's regulatory jurisdiction over all classifications and practices that affect rates in any manner. 40 F.E.R.C. at 61,120.

197. *See Radford, Transmission Access for Cogenerators — Why Make it a Federal Question?*, 120 PUB. UTIL. FORT., Sept. 17, 1987, at 4.

198. *Re Sales of Electricity by Small Power Producers and Cogenerators*, 77 PUR4th 479, 490 (Mass. D.P.U. 1986).

199. *Id.*

200. *Re Wheeling of Cogenerated Energy*, 70 PUR4th 143, 148-49 (Fla. P.S.C. 1985).

201. *Id.* at 149. Florida also allows utilities to deny or curtail transmission services if such service "would adversely affect the adequacy, reliability, or cost of electric service" to the utilities' other customers. *Id.*

utilities to transmit energy from private power producers to other utilities or other facilities owned by the private producer.²⁰²

Wisconsin adopted a voluntary approach to wheeling after its public service commission concluded that the FERC did not want wheeling forced upon utilities.²⁰³ North Carolina and the District of Columbia also adopted voluntary wheeling programs in deference to the FERC's authority to set rates for the interstate transmission of energy.²⁰⁴

5. Data Filing

The requirements for data filing, like the interconnection and wheeling approaches, vary among the states.²⁰⁵ Michigan, for example, insists that utilities provide QFs with data concerning the present and anticipated future avoided cost on the utilities system.²⁰⁶ Michigan utilities must also file, at least every two years, data with the public service commission that includes: present avoided cost calculations, estimates of avoided cost for the next five years, and planned capacity requirements and additions for the next ten years.²⁰⁷

State implementation of PURPA has fostered decentralized power production by creating a large new power generating industry. Although largely successful, cogeneration has caused utilities, cogenerators, and regulators many problems that require solutions to satisfy the goals of PURPA.

202. CONN. GEN. STAT. ANN. § 16-243a(b)(4) (West 1988).

203. Re Cogeneration and Small Power Production, 54 PUR4th 380, 401 (Wis. P.S.C. 1983). The utility must notify the state commission if it does not wish to wheel power. *Id.*

204. Re Rates for Sale and Purchase of Electricity Between Electric Utilities and Qualifying Facilities, 64 PUR4th 369, 391-92 (N.C.U.C. 1985); Re Potomac Electric Power Co., Formal Case No. 757, Order No. 7638 (Aug. 3, 1982), 3 D.C.P.S.C. 359.

205. It has been suggested that national data reporting requirements should be used to clarify certain issues, including: proposed QF sites, the growth potential of new QFs, and the maintainance of operating and efficiency standards. See *FERC Examines Cogeneration with Changes in PURPA Regulation Possible*, 119 PUB. UTIL. FORT., May 14, 1987, at 24. The Edison Electric Institute stated that "[w]ithout this information utilities and state and federal governments will be unable to track the magnitude of QF-produced capacity" *Id.* at 25.

206. Re Cogeneration and Small Power Production, 48 PUR4th 465, 475-76 (Mich. P.S.C. 1982).

207. *Id.*

F. Proposed Changes to FERC Regulations

In response to the problems arising from both PURPA's implementation and the huge growth of the cogeneration industry,²⁰⁸ the FERC recently issued three Notices of Proposed Rulemakings (NOPRs) dealing with changes to the present cogeneration regulations.²⁰⁹ The subject of considerable debate and controversy, these NOPRs signal important changes for all cogenerators with respect to the administrative determination of avoided cost, competitive bidding schemes, and the role of independent power producers.²¹⁰

208. The chairman of the FERC noted this growth:

PURPA has evolved into something beyond everyone's expectations, and has fostered a multi-billion dollar industry providing a majority of the new generating capacity in several regions of the country. The Commission's rules, and the state's implementation of them, did not generally anticipate the large role PURPA has come to play.

FERC Chairman Martha O. Hesse, Remarks Before Senate Committee on Energy and Natural Resources, News Release 317256 (July 9, 1987) (on file at *The Wayne Law Review*).

In terms of electric production, the amount of electric power produced by QFs was more than five times the projected amount from 1980-1985. See Avoided Cost NOPR, *supra* note 169, at 17 n.42.

209. Notice of Proposed Rulemaking, Regulations Governing Independent Power Producers, 53 Fed. Reg. 9327 (FERC proposed Mar. 16, 1988) [hereinafter IPP NOPR]; Notice of Proposed Rulemaking, Regulations Governing Bidding Programs, 53 Fed. Reg. 9324 (FERC proposed Mar. 16, 1988) [hereinafter Bidding NOPR]; Avoided Cost NOPR, *supra* note 169.

The FERC gave the following reasons for amending the cogeneration regulations: (1) PURPA implementation currently causes excessive electricity costs for utilities and their customers; (2) the current regulations place too much risk without sufficient reward to efficient power suppliers that provide reliable and less costly electricity; (3) the existing regulatory system fails to provide enough incentive to make efficient decisions for the future; and (4) increased use of market forces would help to meet the difficulties of a decentralized power supply system. FERC NOTICES OF PROPOSED RULEMAKING ON ELECTRICITY 6 (Mar. 29, 1988) (on file at *The Wayne Law Review*).

210. The NOPRs issued March 16, 1988 contained several changes from earlier drafts due to strong opposition from state utility commissioners. One of the most hotly debated issues was a draft of the Bidding NOPR that dealt with the regulation of multistate utilities. An earlier draft would have required state commissions to jointly conduct bidding programs for multistate utilities on a regional basis, or, in the alternative, the utilities could conduct their own competitive bidding program subject to federal jurisdiction and review by the FERC. Additionally, earlier drafts of the Avoided Cost NOPR would have given the FERC review powers over rates set by multistate utilities when states could not agree on a single regional basis. This provoked great fears that the FERC

The NOPR dealing with administrative determination of avoided cost reaffirms the avoided cost standard as the best method for determining purchase rates for QFs, but adds new requirements and makes suggestions to better implement the standard.²¹¹ In determining avoided cost, the proposed regulations require consideration of a utility's capacity and note that a utility need not make capacity payments when capacity is not needed.²¹² In order to

was trying to preempt the field of multistate utility regulation. See Romo, *Observers Predict Electric Proposals Will "Fundamentally Change" Industry*, 121 PUB. UTIL. FORT., Apr. 14, 1988, at 40 [hereinafter, *Observers*]; Romo, *Four Days in March: When NARUC Took on the FERC*, 121 PUB. UTIL. FORT., Mar. 31, 1988, at 25-28.

The final NOPRs dropped some of the multistate utility regulatory text, and solicited additional comments on the issues of single regional avoided cost rates and single regional competitive bidding schemes. However, many commentators remained concerned with the enduring preemptive aspects. See Opinion of F.E.R.C. Comm'r C. Trabandt, Bidding NOPR, *supra* note 209, at 11-12, 47-48 [hereinafter Trabandt opinion]; Romo, *Observers*, *supra*, at 41.

Another important issue not addressed by the three NOPRs is transmission access, which is currently a matter of bitter debate between utilities and cogenerators. Utilities and their advocates like the Edison Electric Institute raise concerns of consumer protection, system reliability, scheduling difficulties, and resource planning problems if cogenerators are allowed greater access. Romo, *FERC Examines Cogeneration with Changes in PURPA Regulations Possible*, 119 PUB. UTIL. FORT., May 14, 1987, at 24-25. Cogeneration supporters like the Cogeneration Coalition of America respond that cogenerators need more access to help secure true market-based rates. *Id.* at 25-26. See also Haman-Guild & Pfeffer, *Competitive Bidding for New Electric Power Supplies: Deregulation or Reregulation*, 120 PUB. UTIL. FORT., Sept. 17, 1987, at 9, 18-19.

In its 1986 regional conferences, the FERC solicited comments on the transmission access issue. While acknowledging that this was the "most controversial" issue of the conferences, a FERC staff proposal noted that "most parties seemed to agree that transmission questions needed to be evaluated in a broader context than PURPA reform." FERC, SUMMARY OF CURRENT STAFF PROPOSALS ON PURPA-RELATED ISSUES 2 (Sept. 11, 1987) (on file at *The Wayne Law Review*). FERC Chairman Martha Hesse has indicated that the FERC intends to proceed with a reexamination of the present regulation of transmission service. Any changes would be with regard to both transmission pricing and transmission access. Martha O. Hesse, Remarks at the Southeastern Electric Exchange (Mar. 28, 1988) (on file at *The Wayne Law Review*).

211. Avoided Cost NOPR, *supra* note 169, at 28-35.

212. *Id.* at 46-48 (to be codified at 18 C.F.R. §§ 292.304(e)(3)(g)). Consideration of a utility's need for capacity in determining capacity credits was a major concern of the electric utilities. Several major utilities reported substantial overpayment in capacity costs when no capacity was needed. For example, Houston Lighting and Power Company estimates it will make \$500 million in overpayments by 1995. *Id.* at 11 n.24. Niagara Mohawk Power Company has estimated overpayments reaching \$180 million by the year 2000. *Id.* Finally, Pacific Gas & Electric Company estimates "it will incur \$857 million in overpayments *per year* by 1990." *Id.* (emphasis in original).

assure that avoided cost determinations comply with PURPA's goals, the NOPR requires consideration of several factors in determining avoided cost. These factors include the availability of purchases from wholesale sources, the effect of the QF's fuel source on the utility's reliability, and the variability of avoided cost rates during the year.²¹³

The FERC amended its regulation of fixed price contracts to allow greater pricing flexibility. Purchase rates under fixed contracts may differ from avoided cost at the time of delivery. However, purchase rates cannot exceed the total avoided costs "as calculated at the time the obligation is incurred."²¹⁴ Front-end-loaded contracts remain permissible if several factors, including the time value of money, the QF's financial needs, and other equitable considerations are addressed.²¹⁵

The FERC also clarified its regulations pertaining to supplemental, back-up, maintenance, and interruptible power. The Commission clearly stated that interruptible power is adjunct to other services and that utilities are obligated to provide QFs with back-up, supplemental, and maintenance power on both a firm and interruptible basis.²¹⁶ The FERC explicitly interpreted the phrase "upon request"²¹⁷ (regarding when a utility must provide such services to QFs) "to impose an 'absolute obligation' on the utility to provide service"²¹⁸ The FERC also proposed language clarifying a utility's obligation to supply back-up and maintenance power to both the power producing equipment of a QF and any electric loads normally served by that QF.²¹⁹ Finally, the FERC

213. *Id.* at 45-54 (to be codified at 18 C.F.R. §§ 292.304(e)(3-5)).

214. *Id.* at 66 (to be codified at 18 C.F.R. § 292.304(b)(5)).

215. *Id.* at 64-67. The FERC allowed such front end loaded contracts, but also noted these contracts were discouraged because of major problems with inequities to ratepayers and economic inefficiency. *Id.* at 56-59.

216. *Id.* at 75-76 (citing *Oglethorpe, supra* note 147, at 61,135) (to be codified at 18 C.F.R. § 292.305(b)(1)).

"Supplementary power" is "electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself." 18 C.F.R. § 292.101(b)(8) (1988).

"Interruptible power" is "electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions." *Id.* § 292.101(b)(10).

"Maintenance power" is "electric energy or capacity supplied by an electric utility during scheduled outages of the QF." *Id.* § 292.101(b)(11).

217. *See* 18 C.F.R. § 292.305(b) (1988).

218. Avoided Cost NOPR, *supra* note 169, at 76.

219. *Id.* at 78-79 (to be codified at 18 C.F.R. § 292.305(b)(2)). This explicitly resolves the problem raised in the *Alcon* case, *supra* note 186.

requested comments on whether certain factors should be considered in determining back-up and maintenance power.²²⁰

The Avoided Cost NOPR amends the interconnection regulation to permit QFs to own or construct interconnection and transmission facilities under certain conditions.²²¹ These conditions include compliance with all state regulations and require that the interconnection or transmission facility be used for sales and purchases between the QF and utilities.²²²

A second NOPR considers competitive bidding schemes.²²³ Under the proposed regulations, states could establish voluntary bidding programs as an alternative to administrative determinations of avoided cost.²²⁴ State regulators and non-regulated utilities would have the discretion to establish these systems, and the QFs would

220. Avoided Cost NOPR, *supra* note 169, at 82-84. For back-up power these factors include: the expected timing, frequency, and duration of scheduled outages; the expected demand placed on the utility by such outages; and the utility's costs associated with meeting the outages. For maintenance power, the factors include: the ability of the QF to schedule its outages; the duration of the outages; the expected demand placed on the utility by the scheduled outage; and the costs to the utility of providing maintenance power. *Id.* at 83-84.

221. *Id.* at 92-93 (to be codified at 18 C.F.R. § 292.306(c)). The FERC felt that allowing QFs to construct and own such facilities would minimize the costs and improve the efficiency of the interconnection systems. *Id.* at 87-88. Under the current regulations, utilities have little incentive to lower costs, and could actually take measures to discourage interconnection with QFs. *Id.* at 88. Since the QFs had the incentive to increase profits by insuring reliable, efficient systems, the FERC thought it wise to allow QF ownership of interconnection and transmission facilities. *Id.* at 89. This decision was foreseeable; in two prior decisions, the FERC had found interconnection facilities to be within the definition of "qualifying facility." See *Clarion Power Co.*, 39 F.E.R.C. (P) 61,317, at 62,014 (1987); *Kern River Cogeneration Co.*, 31 F.E.R.C. (P) 61,183, at 61,355 (1985).

222. Avoided Cost NOPR, *supra* note 169, at 92-93.

223. Bidding NOPR, *supra* note 209 (to be codified at 18 C.F.R. §§ 292.201-.211).

224. The FERC listed several problems with current avoided cost determinations that could be solved by implementing a bidding program. First, "administrative determination regarding utilities' avoided costs has often been cumbersome, slow, and inconsistent." *Id.* at 8 (footnote omitted). Second, avoided cost calculations have sometimes been inaccurate because of a failure to consider the availability of all of a utility's possible alternative purchase opportunities. *Id.* at 10. Third, selling power to utilities on a first-come, first-serve basis is less efficient than competitive bidding schemes. *Id.* at 11 (footnote omitted).

If bidding systems are adopted, "[a]voided cost need not be an administratively determined number, argued over by experts. Instead, avoided cost could be derived simply and directly from the prices offered from competing suppliers in the bidding process." *Id.* at 14 (footnote omitted).

have an option to participate.²²⁵ Utilities would still be required to buy power from losing and non-participating QFs, but payment would be based only on avoided energy costs.²²⁶

The FERC listed several conditions that must be satisfied if a competitive bidding program is adopted. First, states can reserve capacity for certain technologies or fuels, as long as QFs are allowed to participate.²²⁷ However, no capacity may be exempted from QF participation.²²⁸ Second, the bidding process must con-

225. *Id.* at 12. The FERC stressed that beyond following the conditions provided, implementation of bidding schemes would be up to the states. This leaves room for states to experiment with various programs. *Id.* at 17.

Several states have already adopted competitive bidding schemes as a means of efficiently allocating capacity credits and awarding contracts. Texas, Maine, Massachusetts, and California have implemented such bidding programs; Connecticut, Illinois, and New York are working on similar proposals. See Haman-Guild & Pfeffer, *supra* note 210, at 11-12; Meade, *Competitive Bidding and the Regulatory Balancing Act*, 120 PUB. UTIL. FORT., Sept. 17, 1987, at 22, 24-27.

The Michigan Public Service Commission recently considered whether to adopt competitive bidding as a method for determining avoided cost. In *In re Midland Cogeneration Venture Limited Partnership*, Mich. Pub. Serv. Comm'n Case No. U-8871, (Jan. 31, 1989), the Commission tentatively rejected competitive bidding, reasoning that setting up the system would be too time-consuming at the present. *Id.* at 47. However, the Commission went on to direct the utility involved, Consumers Power, to submit within six months a proposal including a competitive bidding system that eliminates any problems of self-dealing. *Id.* at 110. Therefore, it appears Michigan is close to adopting some type of bidding system.

The preemptive aspects of this NOPR caused much concern. Most state utility commissioners expressed the need for flexibility in setting up bidding programs, yet earlier drafts of the NOPR would have seriously eroded that flexibility. In fact, Commissioner Trabandt's partial dissent to the NOPR states that an earlier proposal "would have had the effect of rendering almost all, if not all, existing state competitive programs illegal and preempted . . ." Trabandt Opinion, Bidding NOPR, *supra* note 209, at 49. Trabandt noted that the current NOPR had undergone serious revision and would require only minor adjustments in existing state programs. *Id.*

226. Bidding NOPR, *supra* note 209, at 26. The FERC tentatively concluded that since QFs are preferred in the bidding process, the QF's bid must be selected in the case of a tie between the bids of a QF and a non-QF. *Id.* at 26-27. The Commission also stated that winning bidders could waive the efficiency standard for oil- and gas-fired cogeneration facilities. *Id.* at 34-36.

227. *Id.* at 36 (to be codified at 18 C.F.R. § 292.302) (footnote omitted).

228. *Id.* at 36-37. "A practice of reserving capacity needs to be met only by a particular supplier would appear to be systematically discriminatory against QFs," thereby violating the statutory obligation to encourage purchase of QF power. *Id.* at 37.

sider all potential supply sources.²²⁹ Third, consideration of non-price factors affecting the security and operation of the purchasing utility's system, including fuel diversity and the QF's reliability, must be explained in writing during solicitation.²³⁰ Fourth, in order that all participants receive equal treatment, the FERC required that full and complete information be available to all parties.²³¹ This includes publicizing such facts as "the quantity and characteristics of capacity needed, the terms of the offer to purchase capacity, the criteria for participation and the criteria for bid selection" ²³² Fifth, states and nonregulated utilities must certify bids to the FERC.²³³ Finally, although only under consideration as a sixth condition, restrictions on negotiating after final bids are submitted may be required.²³⁴

The third NOPR addressed regulations governing independent power producers (IPPs), a class of non-QF power suppliers.²³⁵ The proposed regulations would streamline rate and nonrate regulation of the IPPs in order to realize their benefits to the electric industry and ratepayers.²³⁶

229. *Id.* at 39 (to be codified at 18 C.F.R. § 292.203). The FERC believed this requirement was necessary, for without it, "there is no assurance that a QF will receive a price that is less than or equal to the purchasing utility's real avoided cost." *Id.* at 40. The Commission noted that direct bidding by all potential sources was the most direct and efficient means of fulfilling this requirement. *Id.* at 40-41.

230. *Id.* at 47-49. These factors are listed in 18 C.F.R. § 292.304(e) (1988).

231. Bidding NOPR, *supra* note 209, at 50-51 (to be codified at 18 C.F.R. § 292.204(b)).

232. *Id.* at 50.

233. *Id.* at 53 (to be codified at 18 C.F.R. § 293.211). The FERC reasoned that certification would: (1) ensure state participation in the bidding schemes; (2) minimize controversy over the accuracy of purchase rates; and (3) provide administrative advantages to the FERC. *Id.* at 53-54.

234. *Id.* at 45-47.

235. IPP NOPR, *supra* note 209. IPPs are defined as "wholesale producers (other than qualifying facilities under PURPA) that are unaffiliated with franchised utilities in the area in which the IPPs are selling power and that lack significant market power." *Id.* at 3-4 (footnote omitted). Public utilities may also qualify as IPPs if certain requirements are met. *Id.* at 4 n.4 (to be codified at 18 C.F.R. § 38.103(a)).

236. The FERC recognized several potential benefits of more flexible IPP regulation: (1) IPPs would serve as another source of electric capacity; (2) greater incentives for lower cost IPP power would lower electricity costs; (3) innovative technologies would be fostered; (4) IPPs would assume risks currently borne by ratepayers and utility investors; (5) the number of the PURPA machines would be mitigated; and (6) other indirect benefits. *Id.* at 48-64.

The FERC felt that IPPs "should be freed from traditional embedded cost-of-service regulation" and should be granted greater pricing flexibility under the Federal Power Act (FPA).²³⁷ Thus, the IPPs' sales rates would be deemed just and reasonable under the FPA if they do not exceed the purchasing utility's avoided cost.²³⁸ This avoided cost cap can be determined in a number of ways, including the use of administrative proceedings conducted by the state, through a bidding program, or the purchasing utility can estimate the cap.²³⁹ The FERC rules would allow the IPPs extensive downward pricing flexibility by setting a ceiling on avoided cost rate without setting a floor price.²⁴⁰

Other proposals would exempt IPPs from cost-related accounting and recordkeeping requirements.²⁴¹ IPPs would also be allowed greater flexibility with respect to the disposition of facilities, issuance of securities, and interlocking directorate activities.²⁴² Filing fees would be revised, and any annual charges would be waived.²⁴³ Finally, an advance certification procedure for IPP qualifying status will be adopted.²⁴⁴

These NOPRs reaffirm the vitality of PURPA and its extensive regulatory scheme. They provide a clear signal to prospective operators of cogeneration's bright future and of the continuing importance of PURPA.

IV. FUEL USE ACT

The Powerplant and Industrial Fuel Use Act of 1978²⁴⁵ (FUA) is the second piece of legislation important to potential cogenerators. Depending on fuel use, the FUA may pose problems for some cogenerators, although in practice the FUA is a small obstacle for most cogeneration facilities.

The FUA was enacted as part of the National Energy Act to establish a program for the expanded use "of coal and other alternate fuels as primary energy sources for existing and new

237. *Id.* at 95.

238. *Id.* at 95-98 (to be codified at 18 C.F.R. §§ 38.103(j), .201(b)).

239. *Id.* at 101 (footnote omitted) (to be codified at 18 C.F.R. § 38.201(c)).

240. *Id.* at 102-04 (to be codified at 18 C.F.R. § 38.201(b)).

241. *Id.* at 112 (to be codified at 18 C.F.R. § 38.701).

242. *Id.* at 106-12 (to be codified at 18 C.F.R. §§ 38.301-.506).

243. *Id.* at 115-16.

244. *Id.* at 116-18 (to be codified at 18 C.F.R. §§ 38.601-.603).

245. 42 U.S.C. §§ 8301-8484 (1982), *as amended*, 42 U.S.C.A. §§ 8301-8484 (West 1983 & Supp. 1989) and scattered titles of the U.S.C.

electric powerplants and major fuel-burning installations"²⁴⁶ Its main purposes included: (1) reducing the importation of oil and increasing the country's capability to use indigenous energy resources; (2) conservation of oil and natural gas; and (3) encouraging greater use of coal and other alternate fuels as important energy sources.²⁴⁷

To achieve these goals, the FUA prohibited the use of natural gas or petroleum as primary energy sources in newly constructed electric powerplants, and required these plants to burn coal or some alternate fuel.²⁴⁸ Additionally, existing powerplants were required to convert to coal or some alternate fuel by 1990.²⁴⁹ This conversion requirement was repealed in 1981 as part of the Omnibus Budget Reconciliation Act.²⁵⁰

Amendments to the FUA²⁵¹ repealed its prohibition on the use of natural gas and petroleum as primary fuels for electric powerplants.²⁵² The changes were made because the FUA's impact on fuel choices by new and existing facilities was found to be "far

246. 42 U.S.C. § 8301(a)(1) (1982).

247. *Id.* § 8301(b).

248. *Id.* §§ 8311-12.

249. *Id.* § 8341.

250. 42 U.S.C. § 8341 (1982). The Omnibus Budget Reconciliation Act substituted a voluntary compliance procedure for the conversion requirement. This enabled complying powerplants to receive preferential treatment under the Clean Air Act, 42 U.S.C. §§ 7401-7642 (1982). Existing powerplants switching to coal are exempted from the Clean Air Act's strict new source performance standards. These plants need only satisfy the standards contained in the state implementation plan. *See infra* notes 265-83 and accompanying text.

251. *See* Act of May 21, 1987, Pub. L. No. 100-42, (to be codified in scattered sections of 42 U.S.C.).

252. The House Committee Report listed five reasons for amending the FUA. First, the committee felt that changing market conditions made the use of natural gas and oil more attractive, and that these fuels are reliable and cost-effective energy sources for the future. Second, the committee reasoned that the restrictions that had been placed on the fuel choices of utilities and industries were not justified in the absence of high prices and volume shortages. Instead, the committee favored a diversified approach, with the individual consumer allowed to make his own choices as to fuel use. Third, the decontrol of oil and gas prices removed the "artificially attractive 'below market' prices" for these fuels, in relation to other fuels, which might have led to overconsumption. Fourth, the committee felt it unwise to prohibit the use of oil and gas in light of the financial distress faced by domestic oil and gas producers. Finally, the self-certification procedures included in the amendment would result in lower administrative costs for obtaining exemptions. H.R. REP. No. 78, 100th Cong., 1st Sess., *reprinted in* 1987 U.S. CODE CONG. & ADMIN. NEWS 270, 274-76.

less significant than was originally expected.”²⁵³ Presently, new electric powerplants need only have the “design capability to be converted to coal or another alternate fuel as market conditions warrant in the future”²⁵⁴

The potential conflict between the FUA and cogeneration was readily apparent.²⁵⁵ Under the FUA, if the Secretary of Energy finds that the QF has demonstrated that it cannot obtain the economic and other benefits of cogeneration unless petroleum or natural gas, or both, are used, the facility may be granted an exemption from compliance.²⁵⁶ Both new and existing cogeneration

253. *Id.* at 273. With regard to existing facilities, the House Committee found that the FUA “had no direct impact” on fuel choices. Instead, the reductions in oil and gas consumption were attributed to the phasing out of price controls. *Id.* The FUA’s impact on the construction of new electric powerplants was also viewed as minimal, with more weight given to the broader terms of conservation, the sluggish growth of the economy, and the utilities’ efforts at reducing dependence on oil and gas supplies. *Id.* at 273-74.

254. 42 U.S.C. § 8311(b) (West Supp. 1989) provides:

An electric powerplant has the capability to use coal or another alternate fuel for purposes of this section if such electric powerplant—

(1) has sufficient inherent design characteristics to permit the addition of equipment (including all necessary pollution devices) necessary to render such electric powerplant capable of using coal or another alternate fuel as its primary energy source; and

(2) is not physically, structurally, or technologically precluded from using coal or another alternate fuel as its primary energy source.

Capability to use coal or another alternate fuel shall not be interpreted to require any such powerplant to be immediately able to use coal or another alternate fuel as its primary energy source on its initial day of operation.

Id.

The Committee recognized the possibility of unforeseeable changes in the availability and price of oil and gas, and accordingly included the coal capability requirement. Since the United States has an abundant supply of coal, this requirement mitigates any undue reliance on oil or gas supplies. 1987 U.S. CODE CONG. & ADMIN. NEWS, *supra* note 252, at 276-77.

255. See Polsky, *supra* note 85, at 20.

256. 42 U.S.C. § 8322(c) (1982) applies to new facilities, and § 8352(c) applies to existing facilities. Both provide:

After consideration of a petition (and comments thereon) for an exemption from one or more of the prohibitions of [the FUA], the Secretary may, by order, grant a permanent exemption under this subsection with respect to natural gas or petroleum, if he

(1) finds that the petitioner has demonstrated that economic and other benefits of cogeneration are unobtainable unless petroleum or natural gas, or both, are used in such facility, and

(2) includes in the final order a statement of the basis for such finding.

facilities may be given permanent exemptions from compliance with the fuel use standards.

There are two ways for a QF to prove that the benefits of cogeneration are unobtainable unless oil or gas is used. Under the first method, it must certify that (1) "the oil and gas to be consumed by the cogeneration facility will be less than that which would otherwise be consumed in the absence of the cogeneration," and (2) the use of fuel mixtures is not possible.²⁵⁷ Therefore, greater oil and gas savings exist if the cogeneration plant burned less oil and gas than if the electricity and thermal energy were produced separately.²⁵⁸ QFs must follow specific requirements to prove such savings, including providing certifications, exhibits, and environmental impact statements.²⁵⁹

Under the second method, the QF must demonstrate that (1) "it would be in the public interest to grant an exemption to the cogeneration facility because of special circumstances such as technical innovation, maintaining industry in urban areas, or other reasons which convince [the Department of Energy] that granting the exemption would be in the public interest"; and (2) the use of fuel mixtures is not feasible.²⁶⁰ To show that the exemption would further the public interest, the QF must provide both an explanation of the public interest factors to be considered and an environmental impact statement.²⁶¹

The amendments did not affect the exemption procedures. The exemption process has been employed extensively, and exemptions from the oil and gas restrictions for new facilities have been liberally granted. The Department of Energy (DOE) has validated most claims within a year,²⁶² and "[i]n fact, DOE has never denied a completed petition."²⁶³

This analysis indicates that the FUA will not be an obstacle for cogenerators that comply with the administrative procedures.

257. 10 C.F.R. § 503.37(a)(1) (1988).

258. *Id.* § 503.37(b). The FERC provided a table of the estimated number of Btus of oil or gas that might be saved per kilowatt hour of electricity displaced by cogenerated electricity. The estimated savings range from 100 Btu/kWh in southern Michigan, Ohio, West Virginia, Kentucky, and Indiana to 9900 Btu/kWh in portions of Texas. *Id.* § 503.37(e).

259. *Id.* §§ 503.37(c)(1)(i)-(iii).

260. *Id.* §§ 503.37(a)(2)(i)-(ii).

261. *Id.* §§ 503.37(c)(2)(i)-(ii).

262. *Id.*

263. 1987 U.S. CODE CONG. & ADMIN. NEWS, *supra* note 252, at 273-74.

The prospective cogenerator need only follow the required steps to insure an exemption from any fuel use restrictions.

V. CLEAN AIR ACT

The final part of the regulatory structure affecting cogenerators is the Clean Air Act (CAA).²⁶⁴ The CAA can cause substantial cost problems for the potential cogenerator, depending on the type of fuel used and the resulting emissions.

The CAA and its amendments²⁶⁵ created a complex and comprehensive regulatory scheme for controlling air pollution. It was designed to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the production capacity of its population."²⁶⁶ The CAA empowers both the Environmental Protection Agency (EPA) and the states to enact comprehensive plans to achieve acceptable air quality.²⁶⁷

To implement its goals, the CAA authorizes the EPA to develop National Ambient Air Quality Standards (NAAQSs) for certain pollutants.²⁶⁸ The NAAQSs "specify maximum pollutant concentrations that are deemed by regulation to be safe for exposure over various time periods."²⁶⁹ Ambient standards are generalized and do not pertain to individual source emissions.²⁷⁰ The EPA must issue primary and secondary air quality standards for

264. 42 U.S.C. §§ 7401-7642 (1982).

265. The Clean Air Amendments of 1970 amended the Air Quality Act of 1967, but the changes were so pervasive that they are referred to as the Clean Air Act of 1970. The Clean Air Act Amendments of 1977, Pub. L. No. 95-95, 91 Stat. 685, made major additions to and deletions from the 1970 Act. The entire statute was recodified at 42 U.S.C. §§ 7401-7642 (1982).

For a history of the federal government's regulation of air pollution, see F. ANDERSON, D. MANDELKER & A.D. TARLOCK, ENVIRONMENTAL PROTECTION: LAW AND POLICY 129-35 (1984) [hereinafter F. ANDERSON].

266. 42 U.S.C. § 7401(b)(1) (1982).

267. See Davis, Kurtz, Leape & Magill, *Clean Air Act of 1977: Away from Technology-Forcing?* 2 HARV. ENVTL. L. REV. 1, 4 (1977).

268. The CAA regulates only those pollutants "which may reasonably be anticipated to endanger public health or welfare" and which are emitted "from numerous or diverse mobile or stationary sources." 42 U.S.C. §§ 7408(a)(1)(A)-(B) (1982).

At present, there are six criteria pollutants: sulfur oxides, particulate matter, carbon monoxide, ozone, nitrogen dioxide, and lead. For a discussion of these pollutants and their detrimental effects, see F. ANDERSON, *supra* note 265, at 120-25.

269. F. ANDERSON, *supra* note 265, at 137.

270. *Id.*

each of the criteria pollutants.²⁷¹ Primary standards are aimed at protecting the public health with "an adequate margin of safety."²⁷² Secondary standards "protect the public welfare from any known or anticipated adverse effects" on other environmental resources such as water, vegetation, wildlife, and property.²⁷³

To complement the NAAQSs, the CAA also authorizes the EPA to set uniform national technology-limited emission requirements for particular sources of air pollution. Under this provision, New Source Performance Standards (NSPS) were created to control the emissions from new stationary sources.²⁷⁴ Major new stationary sources are required to use the "best system of continuous emission reduction" to meet the performance standards.²⁷⁵ These systems are defined as precombustion cleaning and fuel treatments or other processes that are "inherently low-polluting or nonpolluting."²⁷⁶ Gas-fired cogenerators should have no difficulty meeting the CAA requirements; however, waste- or coal-fired facilities could face major capital costs for emission control equipment.

Under the CAA, state and local governments have the primary responsibility for air pollution prevention and control. The Act requires that the states formulate State Implementation Plans (SIPs) to enforce and maintain the primary and secondary air quality standards.²⁷⁷ Once approved by the EPA, these SIPs have the force of state and federal law and may be enforced by both state and federal agencies.²⁷⁸

The 1977 amendments set up different SIP requirements for regions not yet meeting the NAAQSs (nonattainment areas), and for regions with air quality exceeding the NAAQSs (attainment

271. 42 U.S.C. § 7409(a)(1)(A) (1982). The EPA's regulations setting the primary and secondary standards for the criteria pollutants are located at 40 C.F.R. §§ 50.1-.12 (1987). It should be noted that carbon monoxide has only a primary standard. The secondary standard was eliminated several years ago. See *Current Developments*, 16 *Env't Rep.* 859 (BNA 1985).

272. 42 U.S.C. § 7409(b)(1) (1982).

273. *Id.* §§ 7409(b)(2), 7602(h).

274. *Id.* § 7411. "New source" and "stationary source" are defined in §§ 7411(a)(2), (3).

275. *Id.* § 7411(a)(1)(C).

276. *Id.* §§ 7411(a)(7)(A)-(B).

277. *Id.* § 7410(a)(1). For the general requirements pertaining to the mechanics of the SIPs, see 40 C.F.R. §§ 51.1-.328 (1988). The regulations dealing with the promulgation and approval of SIPs are contained in 40 C.F.R. §§ 52.01-.2850 (1988).

278. 42 U.S.C. § 7413 (1982).

areas).²⁷⁹ In nonattainment areas, major new sources must obtain permits that limit their emissions. The permits also require the source to use equipment that will achieve the lowest achievable emissions rate (LAER).²⁸⁰ The SIP requirements in attainment areas are designed to prevent significant deterioration of the high air quality,²⁸¹ and new plants in these areas must use the best available control technology (BACT).²⁸² States are given wide discretion in implementing the LAER and BACT standards.

The CAA also regulates interstate air pollution. The Act requires states to implement SIPs that will prevent stationary sources from emitting any pollutant that will either "prevent attainment or maintenance by any other State of any such national primary or secondary ambient air quality standard," or "interfere with measures required to be included in the applicable implementation plan for any other State . . . to prevent . . . deterioration of air quality or to protect visibility" ²⁸³

For prospective cogenerators, the existence and magnitude of CAA problems will depend on the fuel source used. Systems using coal or waste can expect to encounter the most problems with the CAA requirements, because the emissions from such fuel sources contain large amounts of the criteria pollutants. Thus, those systems will likely incur the higher capital costs involved in installing mandatory cleaning systems. A cogenerator must work closely with state officials to ensure that plant emissions meet the CAA requirements.

VI. DETROIT COGENERATION PROJECT

The Detroit cogeneration project is the largest facility of its kind in the world today. It is a product of PURPA, and subject to the breadth of its regulatory structure. The project serves as a prime example of the problems cogenerators face in entering the field of electric power supply.

279. *Id.* § 7501(2).

280. *Id.* § 7501(3). "LAER was intended to be the strictest of the Clean Air Act's technology-based standards, stricter than the 'best available control technology' (BACT) applicable in clean air areas, which in turn is stricter than the NSPS." F. ANDERSON, *supra* note 265, at 245. See also *infra* note 330.

281. 42 U.S.C. §§ 7470(1)-(5).

282. *Id.* § 7475(a)(4). For a definition of BACT, see *infra* note 321.

283. *Id.* § 7410(a)(2)(E).

A. Detroit's Central Steam Heating System

Detroit has had a central steam heating system since 1903,²⁸⁴ when the Detroit Edison Company was organized to build and operate an electric power plant to supply energy to the electric companies already serving the city.²⁸⁵ By 1915, Detroit Edison had become the sole provider of steam heat for the central city.²⁸⁶ The steam output of the central heating system expanded greatly under Edison's control through the 1950s.²⁸⁷

The system reached peak sales in 1972.²⁸⁸ However, economic factors have since caused a decline in sales. The system lost profitability due to rapidly increasing natural gas and oil prices.²⁸⁹ To offset higher fuel costs, Detroit Edison raised the retail rate for steam. As a result of the increased rates, new customers have been reluctant to connect with the system, and some customers disconnected service.²⁹⁰

Alternative and less expensive methods of generating steam would enable the central steam heating system to become a source of potential economic development by stabilizing energy prices. Because of its ability to produce and use steam while simultaneously addressing Detroit's major solid waste problem, cogeneration became an attractive means of revitalizing Detroit's steam heating system.

1. The Project

On September 14, 1981, Detroit announced plans for construction of the Greater Detroit Resource Recovery Facility (GDRRF).²⁹¹

284. R. MILLER, *KILOWATTS AT WORK — A HISTORY OF THE DETROIT EDISON COMPANY* 166-74 (1957).

285. *Id.* at 172.

286. *Id.* at 174. The actual number of customers for the steam heat declined from 1920-1950, and the system was a break even business. "[I]t was maintained and even extended because of the profitable electrical load which was related to it." *Id.*

287. By 1980, sales had fallen to 2.23×10^9 kg, and the number of customers had fallen to 764. McLain, Brinker & Gatton, *Potential Benefits of a Resource Recovery Facility Coupled with District Heating in Detroit, Michigan*, ORNL/TM-8463 (Sept. 1982).

288. By the late 1970s, natural gas provided 88 percent of the fuel for the district steam heating system, fuel oil provided 7 percent, and coal 5 percent. For 1981, the steam heating system showed a loss of \$1.8 million, with fuel supplies accounting for 82% of the system's operating costs. *Id.*

289. *Id.*

290. *Id.* For example, the Renaissance Center, a major downtown Detroit office and hotel complex, elected to install its own heating system instead of interconnecting with the central steam heating system.

291. Solid waste disposal is the primary function of the GDRRF. The city

This bottoming-cycle cogeneration facility will serve the city by providing both a solid waste disposal method and an alternate source of steam for the district heating system.²⁹² The GDRRF will process non-hazardous solid waste from residential and commercial sources. Detroit Edison will purchase both the steam and the electricity produced by the GDRRF.²⁹³

The facility is "capable of processing up to 4000 tons of solid waste per day."²⁹⁴ Residue that remains after processing, involving approximately "8% by volume and 14% by weight of the original refuse," will be landfilled.²⁹⁵

The power-generating facility includes three identical refuse-derived, fuel-fired, spreader-stoker boilers, two of which will operate while the third serves as a back-up. Particulate emissions from the operating boilers are controlled by a five-stage electrostatic precipitator, with the remaining exhaust released through the stacks. The boiler fly ash and bottom ash from the travelling grates are collected in a water tank, dried, and then stored in an ash storage building. In addition to supplying the low pressure steam demand of the city's central heating system, the boilers provide high pressure steam to produce 70MW of electricity.²⁹⁶ The heat output from the plant is dissipated through water cooling condensers. The plant also has a state of the art odor control strategy, including a first-in, first-out system, dry processing, odorous materials removal, and daily maintenance.²⁹⁷

collects approximately 3000 tons of solid refuse daily. This solid waste must be compacted and transported to landfill sites outside the city. Detroit's solid waste fills about 60 acres of landfill each year, and since its Wayne County landfills have very short remaining lives, the city will soon be forced to haul its refuse to more distant landfills. This will result in increased transportation costs. When operable, the GDRRF will significantly reduce the volume of waste requiring landfilling, thereby substantially easing the landfill space problem.

292. Reoffering Statement of the Greater Detroit Resource Recovery Authority at iii (1986) [hereinafter Reoffering Statement] (on file at *The Wayne Law Review*).

293. *Id.*

294. *Id.* at 13. This capacity "exceeds the amount of waste [currently] collected by the city by more than 200,000 tons per year." *Id.* Consequently, Detroit will be forced to haul waste from other cities in order to operate the facility efficiently.

295. *Id.*

296. Michigan Department of Natural Resources, Air Quality Division Staff Activity Report 2 (Oct. 16, 1984) (on file at *The Wayne Law Review*).

297. *Id.*

The GDRRF is funded with proceeds from the sale of tax-exempt industrial revenue bonds totaling \$438 million.²⁹⁸ Revenue from several sources will be used to cover the annual debt service requirements and operational costs of the GDRRF including: the sale of steam, electricity and ferrous metals; hauling fees; and city tipping fees.²⁹⁹

2. *Effect of Federal Statutes*

a. *PURPA*

The Michigan Public Service Commission (MPSC) initiated proceedings to implement PURPA one year after the FERC issued PURPA regulations.³⁰⁰ The MPSC issued an initial order that required each utility to: (1) "amend its tariffs to remove any existing prohibitions" against selling to, purchasing from, or operating in parallel with cogenerators or QFs; and (2) to file interim electricity purchase rates equal to the average cost of fuel and purchased power as determined by the most recent rates. The order also instituted an in-depth review of obligations and alternatives to carrying out PURPA.³⁰¹

The MPSC final order fully implemented PURPA and encouraged joint ventures between QFs and utilities within the FERC guidelines.³⁰² The MPSC determined that including utilities in cogeneration plans would add needed expertise and capital to an emerging technology, and would also help control high energy costs.³⁰³

The FERC certified the GDRRF as a QF under the federal regulations.³⁰⁴ Detroit Edison, as an electric utility under PURPA, is subject to the rules and regulations of the MPSC. Because PURPA requires utilities to purchase energy from QFs, Detroit

298. The Resource Recovery Authority reoffered \$500 million worth of adjustment/fix rate bonds, which were first issued in December 1984. Reoffering Statement, *supra* note 292, at 1.

299. *Id.* at 7-9.

300. The initial order was issued by the Michigan Public Service Commission on March 17, 1981. For a history of the proceedings that led to the MPSC's final order, see *Re Cogeneration and Small Power Production*, 48 PUR4th 465, 469-70 (Mich. P.S.C. 1982).

301. 48 PUR4th at 467.

302. The final order was issued on August 27, 1982. *Id.* at 473-74.

303. *Id.*

304. 32 F.E.R.C. (P) 62,100, at 63,094-95 (1985).

Edison must purchase the GDRRF's excess power output.³⁰⁵

On December 16, 1985, Detroit Edison and the GDRRF entered into an energy purchase agreement.³⁰⁶ The agreement provides that Edison's primary objective is the purchase of steam for resale to its customers; "the purchase of electricity is secondary"³⁰⁷ Edison will purchase all of the steam and electricity generated by the GDRRF.³⁰⁸ Steam that the GDRRF generates and that Edison is unable to purchase will be converted into electricity, which Edison must buy pursuant to PURPA.

The amount of steam that the GDRRF sells to Edison is at least the current scheduled annual quantity of 2.8 million Mlbs (1 Mlb = 1000 pounds). Adjustment provisions are included in the agreement to allow flexibility in the scheduled quantity. Edison has the option to purchase steam in excess of the scheduled amount and to require the facility to burn alternate fuel to meet the scheduled steam quantity.³⁰⁹

b. Fuel Use Act

Since the GDRRF burns waste as its primary fuel source, the FUA does not pose a significant problem to the project.³¹⁰ The

305. See *supra* notes 68-73 and accompanying text. Under PURPA, the QF and the utility may contract on their own to determine the avoided cost as reflected in the purchase rate. See *supra* notes 143-46 and accompanying text. Some waste-to-energy cogeneration facilities may be at a disadvantage in comparison to other cogeneration facilities because of the low avoided energy component when waste is used as fuel, and because of the comparatively long lead times necessary for the construction and development of waste-to-energy plants. See Pestle & Butler, *supra* note 175, at 30.

In order to encourage the utilization of waste-to-energy facilities, some states have specified relatively high electric payment rates for waste-fueled energy. For example, New York, Connecticut, and Illinois have adopted such statutes to help even the competition. *Id.*

Michigan recently adopted legislation to encourage the use of resource recovery facilities like the GDRRF. 1989 Mich. Legis. Serv. 1 (West) (to be codified at MICH. COMP. LAWS ANN. § 460.60 (West 1989)). The statute requires Michigan utilities to pay full avoided cost when purchasing power from waste-to-energy facilities. This cost includes an automatic capacity rate component.

306. Reoffering Statement, *supra* note 292 at 57-67. The agreement is effective for 20 years after the commencement date, or until December 13, 2008, whichever is later.

307. *Id.* at 57

308. *Id.* at 57-58.

309. *Id.*

310. The FUA originally prohibited the use of natural gas or petroleum as primary energy sources, but now allows their use if the facility has the capability to use coal or another fuel. See *supra* notes 249-51 and accompanying text.

use of waste as a primary fuel is outside the ambit of the original restriction and the amendment. Waste is an abundant fuel source that will continue to be available in the future.

The GDRRF does have the capability to burn diesel fuel in the event Detroit Edison wishes to buy electric power beyond that produced by burning waste. However, diesel fuel will only be burned in start-up procedures or in time of emergency. Therefore, it falls outside the definition of "primary fuel source" under the FUA and is not subject to the Act's requirements.³¹¹

c. Clean Air Act

The GDRRF will have significant emission problems because it burns solid waste. The technology used in the facility to control air pollution has been a continuing source of controversy, and has been challenged by the EPA and several environmental groups.

The CAA requires new major emitting facilities³¹² whose emissions may detrimentally affect air quality to obtain an emissions permit that details their limitations.³¹³ These limitations must conform to the CAA's goal of preventing significant deterioration (PSD) of air quality in attainment areas. The GDRRF is located in the Metropolitan Detroit-Port Huron Intrastate Air Quality Control Region,³¹⁴ which is classified as attainment for sulfur dioxides and oxides of nitrogen, and nonattainment for total suspended particulates and carbon monoxide.³¹⁵

The EPA has expressly delegated complete authority to the State of Michigan to issue permits and implement PSD regulations

311. 42 U.S.C.A. § 8302(a)(15) (West 1983 & Supp. 1989) provides: The term "primary energy source" means the fuel or fuels used by any existing or new electric powerplant, except it does not include, as determined under rules prescribed by the Secretary—

(A) the minimum amounts of fuel required for unit ignition, startup, testing, flame stabilization, and control uses, and

(B) the minimum amounts of fuel required to alleviate or prevent (i) unanticipated equipment outages and (ii) emergencies directly affecting the public health, safety, or welfare which would result from electric power outages.

Id.

312. See 42 U.S.C. § 7479(1) (1982) for the definition of "major emitting facility."

313. *Id.* § 7475(a)(1).

314. 40 C.F.R. § 81.37 (1988).

315. *Id.* § 81.323.

with respect to each pollutant regulated by the CAA.³¹⁶ The EPA delegated this authority only after its Region V staff had evaluated state practices and found that they met the CAA standards.³¹⁷ Michigan's authority is conditioned on the Michigan Department of Natural Resources (MDNR) reporting a summary of its findings relative to the PSD application and its justifications for its preliminary determination to the EPA at the beginning of the permit comment period.³¹⁸ The EPA must notify the MDNR of its concerns about the pending permit before the end of the comment period.³¹⁹

PSD permits are issued only after thorough review by all concerned state agencies. In the first step of the state's permit procedure, the MDNR reviews the permit application. A second review is conducted by the Michigan Air Pollution Control Commission (MAPCC), which has the power to issue or deny the permit. A mandatory public hearing is then held for the purpose of allowing all interested parties to present evidence.³²⁰ Each PSD application must demonstrate that, among other things, the facility will install the "best available control technology" (BACT) for each pollutant under the PSD regulations.³²¹

316. The delegation agreement states in part:

7. The primary responsibility for enforcement of the PSD regulations in the State of Michigan will rest with the Air Quality Division [of the MDNR]. The AQD will enforce the provisions and regulations that pertain to the PSD program except in those cases where the rules or policy of AQD are more stringent; in which case the State may elect to implement the more stringent requirement. If the State enforces the delegated provisions in a manner inconsistent with the terms and conditions of this delegation or the Clean Air Act, USEPA may exercise its enforcement authority . . . with respect to sources within the State of Michigan subject to PSD provisions.

8. If the Regional Administrator determines that the State is not implementing or enforcing the PSD program in accordance with the terms and conditions of this delegation, the requirements of 40 CFR section 52.21, or the Clean Air Act, this delegation, after consultation with the AQD, may be revoked in whole or in part

45 Fed. Reg. 8,348-49 (1980).

317. *Id.* at 8,348.

318. *Id.*

319. *Id.*

320. *Id.*

321. 42 U.S.C. § 7479(3) (1982) defines BACT as "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable"

After the GDRRF filed its permit application on September 13, 1984, the Greater Detroit Resource Recovery Authority (GDRRA) published a Notice of Public Hearing, which provided for both a thirty day comment period and a public hearing. The notice indicated that the state had made a "preliminary determination that the construction of the project would not violate the [CAA]" or other state and federal laws.³²² The state, as required, sent the EPA a copy of the notice. The EPA made no response during the comment period and did not appear at the public hearing.

At the hearing, the use of scrubber/baghouse technology, an advanced emissions cleaning process, was discussed.³²³ However, the scrubber technology would have increased tipping fees by at least forty percent and rendered the facility noncompetitive and economically unfeasible.³²⁴ Consequently, the review board found that the BACT would be a fuel preprocessing method, which it felt constituted fuel "treatment" within the definition of BACT.³²⁵ The MDNR issued the facility's permit on November 9, 1984.³²⁶

On April 9, 1986, the MDNR held a special meeting to consider whether the permit had any problems.³²⁷ After considering various

322. See Complaint, Greater Detroit Resource Recovery Auth. v. Adamkus, 677 F. Supp. 521 (E.D. Mich. 1987) at 9 (on file at *The Wayne Law Review*).

323. There are two types of scrubbing: wet and dry. In wet scrubbing, "exhaust gases in the stack with absorbent chemicals, . . . react with the SO₂ in the stack to form a solid sludge that can be removed and disposed of on land." F. ANDERSON, *supra* note 265, at 208. Wet scrubbing was ruled out for the GDRRF because of the open land area required for settling. Report from Combustion Engineering to EPA, Exhibit H of Complaint, *supra* note 322 at 33, [hereinafter C-E Report]. Dry scrubbing involves scrubbing of the exhaust gas with dry lime or limestone and involves little or no wet chemicals. F. ANDERSON, *supra* at 208.

324. The firm constructing the facility, Combustion Engineering, argued strenuously that including a dry scrubber would increase capital costs, operational and maintenance costs, detrimental environmental effects, and tipping fees. See C-E Report, *supra* note 323, at 38-46.

325. 42 U.S.C. § 7479(3) (1982) provides that BACT is achievable "through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant."

The fuel preprocessing method utilized at the GDRRF involves various sorting techniques designed to reduce the sulfur content of the refuse. Since solid waste is inherently low in sulfur, the amount of sulfur dioxide passing through the stacks will be low. C-E Report, *supra* note 323, at 46.

326. Complaint, *supra* note 322, at 10.

327. This meeting was held as a result of conflicting letters sent to the City

presentations, the MDNR determined that there was no need to reconsider the permit. EPA officials were unable to submit comments until the next day. The EPA's comments stated that the permit was deficient for not incorporating the scrubber technology.³²⁸

The EPA issued a Notice of Violation, finding that the permit violated the Michigan SIP and Part D of the CAA.³²⁹ The EPA based its determination on the fact that the permit did not require the lowest achievable emission rate (LAER)³³⁰ for particulate matter and carbon monoxide, which is nonattainment in the facility's region.³³¹ On May 20, 1986, based on these deficiencies, the EPA revoked the MDNR's delegated authority to regulate the GDRRF.³³²

of Detroit and Combustion Engineering by the Air Quality Division (AQD) of the MDNR that reflected the AQD's belief that scrubbers might be the BACT. See *Greater Detroit Resource Recovery Auth. v. Adamkus*, No. 86-CV 72910-DT, slip. op. at 3-4 (E.D. Mich. Oct. 21, 1986) [hereinafter *Adamkus* slip op.].

328. Testimony of the EPA Before the MAPCC on the Proposed Construction of the Detroit Recovery Facility, Exhibit G of Complaint, *supra* note 322, at 3 [hereinafter EPA Testimony].

329. Letter from David Kee, Director Air Management Division, EPA Region 5 to Bella Marshall, Exhibit H of Complaint, *supra* note 322.

330. *Id.* LAER is defined as that rate of emissions which reflects:

(A) the most stringent emission limitation which is contained in the implementation [plan] of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

42 U.S.C. § 7501(3) (1982).

331. The LAER is required by the Michigan Air Pollution Control Commission R336.1221(a) for sources of particulate matter and carbon monoxide emissions. The GDRRF is a major stationary source under 42 U.S.C. § 7602(j) (1982). 42 U.S.C. § 7502(b)(6) (1982) provides that SIP provisions shall require permits for new major stationary sources in nonattainment areas. Permits may be granted only if the proposed source complies with the LAER for nonattainment pollutants. *Id.* § 7503.

332. Letter from Valdas Adamkus, EPA Region 5 Administrator, to Robert Miller, Air Quality Division, MDNR (May 20, 1986), Exhibit I, Complaint, *supra* note 322. The EPA contended that it had never revoked or modified the GDRRF's permit. See Defendants' Response to Plaintiffs' Motion to Dismiss or, in the Alternative, Cross Motion for Summary Judgment, *Greater Detroit Resource Recovery Auth. v. Adamkus*, 677 F. Supp 521 (E.D. Mich. 1987) at 14 [hereinafter Response Brief] (on file at *The Wayne Law Review*). The EPA viewed the May 20, 1986 letter as merely expressing the regional administrator's (Mr. Adamkus) intent to begin revocation proceedings. A review of the case led Mr. Adamkus to conclude there was "insufficient basis" to pursue the revocation, and accordingly the EPA issued a letter, dated September 19, 1986, withdrawing the May 20 letter. *Id.*

The GDRRA and Combustion Engineering, the builder of the project, brought suit for injunctive and declaratory relief to halt the EPA revocation proceedings.³³³ The District Court for the Eastern District of Michigan granted the plaintiffs' motion for summary judgment, enjoining the EPA from revoking the permit.³³⁴ The court reviewed the EPA's authority to revoke the permit and found that, under condition eight of the delegation agreement, the EPA could revoke the permit in whole or in part if it determined that the state was "not implementing or enforcing the PSD program in accordance with the terms and conditions of this delegation"³³⁵ However, the court noted that the EPA had previously audited the Michigan implementation and enforcement

333. *Adamkus* slip op., *supra* note 327. Before trial began, the plaintiffs discovered the EPA audits of the MDNR's permitting process and the GDRRF's permit. Earlier, the EPA had denied conducting such audits, but released them to the plaintiff after discovering its error. The disclosed audits praised the permitting process and found the permit satisfactory. The EPA did not challenge the audit's findings and simply withdrew its revocation letter of May 20, 1986. 677 F. Supp. at 525. Nonetheless, the plaintiffs continued their suit in order to stop future interference with the permit.

334. *Adamkus* slip op., *supra* note 327, at 18. The district court rejected the defendant's arguments of the case being moot, unripe, and that the court lacked subject matter jurisdiction.

First, the court found that the case was not moot because an actual case and controversy existed. *Id.* at 13. Although the EPA had withdrawn its revocation letter, the EPA's continued assertion of inherent authority could clearly affect the GDRRA's actions. Additionally, the court stated that even if no case or controversy existed, the case would fall into the exception for controversies capable of repetition yet evading review. *Id.* at 13. *See* *Southern Pacific Terminal Co. v. ICC*, 219 U.S. 498, 515 (1911).

Second, the court found the case to be ripe under the two part test set forth in *Abbott Laboratories v. Gardner*, 387 U.S. 136 (1967). The test includes a determination of (1) the fitness of the issues for judicial decision, and (2) the hardship to the parties of withholding court consideration. 387 U.S. at 149. The first component requires final agency action for review. The district court held that final agency action occurred when the permit was first issued by the state on November 9, 1984, pursuant to the delegation agreement. *Adamkus* slip op., *supra* note 327, at 14. The court also found that the hardship requirement was satisfied, noting the hundreds of millions of dollars involved in the financing bonds and the effect that continued EPA intervention would have on their repayment. *Id.* at 14-15.

Third, the court found federal subject matter jurisdiction under 28 U.S.C. § 1337, which provides original jurisdiction in the district courts for congressional acts regulating commerce. Since the Clean Air Act regulated commerce, jurisdiction existed. *Id.* at 15-16.

335. *Adamkus* slip op., *supra* note 327, at 17. *See* 45 Fed. Reg. at 8,348 (1980).

procedures and found them commendable.³³⁶ Because the EPA did not submit evidence to the contrary, the court held that the EPA had no basis for revoking the permit under condition eight.³³⁷

Alternatively, the EPA argued it retained the "implied power" to revoke the permit.³³⁸ The court found this claim inconsistent with the express grant of revocation powers to the EPA,³³⁹ which details the situations in which the EPA can revoke permits and the procedures that must be followed. The court reasoned that any authority beyond these limits was unwarranted.³⁴⁰

336. *Adamkus* slip op., *supra* note 327, at 17. The court quoted part of the EPA audit report relating to the MDNR's new source review program:

The MDNR is commended for the continuing dedication of its staff to the task of making and documenting complete reviews of new source applications. As has been reported in earlier audits, the Staff Activity Reports which are on file for all sources submitted for review by the Michigan Air Pollution Control Commission (MAPCC) are noteworthy efforts to document all factors considered in reviews of such applications. This audit revealed no real departures from observance of and adherence to continuing good practices.

677 F. Supp. at 523.

In addition, the court noted that in reviewing the GDRRF's permit, the EPA stated:

"MDNR continues to competently perform the air quality analyses required by the regulations, and a general impression obtained from the audit is that there has been an increase in State activity in performing independent internal reviews of modeling analyses contained in permit applications." The EPA auditors did note, however, that in some instances, as in the case of the GDRRA facility, the MDNR had substituted existing data without a showing it was "representative."

Id. at 524.

The EPA disputes the implication that the permit program was foolproof. They contend that the program was never audited for BACT, and that the BACT deficiencies are quite clear in the audit report. Telephone interview with Eric Cohen, Assistant Regional Counsel, EPA (Mar. 3, 1989).

337. *Adamkus* slip op., *supra* note 327.

338. See Response Brief, *supra* note 332, at 39-42 for an explanation of the legal theory behind this argument.

339. *Adamkus* slip op., *supra* note 327, at 17-18.

340. *Id.* The district court also awarded attorney fees to the GDRRA. 677 F. Supp. 521, 529. The award was based on provisions of the Equal Access to Justice Act, 28 U.S.C. § 2412(d)(1)(A) (Supp. III 1985), that allows attorney fees unless the government's position as a litigant is "substantially justified," or if special circumstances make an award unjust. *Id.* The court found that the EPA had "no justification, factual or legal, for its actions." 677 F. Supp. at 527. The court also stated it would be unjust *not* to award fees here, as the EPA revoked the delegated authority solely to pacify vocal environmental groups. *Id.* Combustion Engineering was awarded fees under another provision of the Equal

The Detroit project illustrates that prospective cogenerators must be concerned with suits brought under both federal and state law. The EPA controversy was based on federal law. Just six months after the EPA decision, four environmental groups and the Canadian Province of Ontario filed suit in federal court alleging state law claims.³⁴¹

The environmental groups sought "relief from pollution or impairment of the air, the water, and other natural resources of the State of Michigan threatened by the GDRRF"³⁴² under the provisions of the Michigan Environmental Protection Act (MEPA).³⁴³ Specifically, the plaintiffs alleged that the GDRRA and Combustion Engineering violated their statutory duty to minimize or prevent environmental harm by planning to install inadequate air pollution control devices, having inadequate residue disposal plans, and failing to have separation and recycling measures.³⁴⁴ Moreover, the organizations alleged that the defendants violated their duty to consider and determine the environmental impact of the facility and to consider possible alternatives. Under each count, the environmental groups sought an injunction stopping construction of the facility.

The Ontario plaintiffs alleged under the MEPA that "the incinerator as proposed will or is likely to pollute, impair, or destroy the air, water, and other natural resources of the State of Michigan and the Province of Ontario, and the public trust therein"³⁴⁵ The court held that the Ontario plaintiffs lacked standing to sue.³⁴⁶ The court found that they had not demonstrated an "injury in fact,"³⁴⁷ as the MEPA only addresses Michigan's natural resources, "in which Ontario, a foreign government, has no recoverable interest or claim."³⁴⁸

Access to Justice Act, 28 U.S.C. § 2412(b) (Supp. III 1985). The award was based on the EPA's bad faith in actions giving rise to the claim and in litigating the case. 677 F. Supp. at 528-29. This decision is currently on appeal.

341. *Detroit Audubon Soc'y v. City of Detroit*, No. 87-CV-71577-DT slip op., (E.D. Mich. Feb. 24, 1988). The four environmental groups were the Detroit Audubon Society, the North Cass Community Union, the Sierra Club, and the Environmental Defense Fund.

342. *Id.* at 3-4.

343. MICH. COMP. LAWS ANN. §§ 691.1201-.1207 (West 1987).

344. *Detroit Audubon Soc'y* slip op., *supra* note 341, at 3-4.

345. *Id.* at 4.

346. *Id.* at 8.

347. *Id.* at 7 (citing *Gladstone Realtors v. Village of Bellwood*, 441 U.S. 91, 99 (1979)).

348. *Id.* at 8.

The defendants moved for summary judgment on both plaintiffs' claims. The defendants first argued that the environmental plaintiffs' lawsuit was untimely and barred by the doctrine of laches. The court, applying the test set forth in *State of Michigan v. City of Allen Park*,³⁴⁹ found that laches applied. It specifically noted the six month delay following the resolution of the first suit, the fact that the facility was over seventy percent complete with completion expected in the late summer or fall of 1988, and the \$438,000,000 municipal bond expenditure.³⁵⁰ The court held that the plaintiffs had delayed in bringing suit and that this unnecessary delay was prejudicial to the defendants, who had complied with every permit requirement.³⁵¹

The defendants also argued that both plaintiffs had failed to state a legally cognizable claim under the MEPA.³⁵² The court held that even assuming the plaintiffs had established a prima facie MEPA case, the issuance of the federal permit "creates an un rebuttable presumption that the defendants' conduct is consistent with the promotion of the health, safety, and welfare of Michigan citizens and that no feasible and prudent alternatives are available."³⁵³ The court went on to note that the traditional deference given to an agency's reasonable interpretations precludes a judicial de novo review of agency decisions.³⁵⁴

VII. CONCLUSION

The use of cogeneration is promoted by a regulatory structure that guarantees a market for the surplus power produced by

349. 501 F. Supp. 1007 (E.D. Mich. 1980). The doctrine of laches applies if (1) the plaintiffs delay filing suit, (2) the delay prejudices or harms the defendant(s), and (3) the delay is inexcusable. *Id.* at 1016-17.

350. *Detroit Audubon Soc'y*, slip op., *supra* note 341 at 15.

351. *Id.* at 16.

352. In order to establish a prima facie case under the MEPA, a plaintiff must show that the defendants' conduct "has, or is likely to pollute, impair or destroy the air, water or other natural resources or the public trust therein" MICH. COMP. LAWS ANN. § 691.1203(1) (West 1987). Defendants may rebut the prima facie case by showing (1) that their conduct is consistent with the public health, safety, and welfare, and (2) that no feasible and prudent alternative exists.

The defendants in *Detroit Audubon Soc'y* also argued that the plaintiffs were barred from bringing suit by res judicata. The district court rejected this claim, holding that the plaintiffs were not in privity with the EPA, the plaintiff in the prior case. *Detroit Audubon Soc'y* slip op., *supra* note 341, at 17.

353. *Detroit Audubon Soc'y* slip op., *supra* note 341, at 21.

354. *Id.* at 25 (citing *National-Southwire Aluminum Co. v. EPA*, No. 86-3982 (6th Cir. 1988)).

cogenerators. Through the enactment of PURPA, Congress clearly stated the national goal of encouraging the more efficient use of energy resources.

State commissions have historically exercised control over the retail market for electric power and have the primary responsibility for implementing PURPA under the FERC guidelines. States have independently carried out the federal mandate in accordance with local needs, conditions, and persuasions. As a result, cogeneration is subject to a range of regulatory patterns. After ten years of experience under PURPA, the proposed FERC amendments³⁵⁵ represent a reaffirmation of PURPA's goals and an attempt to correct its weaknesses to enable more effective state implementation of the statute. In order to realize the full benefits of cogeneration's regulatory structure, the prospective cogenerator must carefully adhere to the requirements of PURPA, the FUA, and the CAA.

The construction and approval process for the GDRRF is a prime example of the workings of the regulatory structure governing cogeneration in the United States. The extensive CAA litigation involving the GDRRF illustrates the opposition a cogenerator may meet in initiating and completing the facility. More important, the litigation's outcome proves that compliance with state and federal procedures required under the CAA will lead to vindication of a cogenerator's right to build and operate a cogeneration facility.

In the last analysis, the implementation of PURPA has caused an unprecedented boom in cogeneration, fostering substantial growth in virtually every state. The future for cogeneration appears bright.

355. See *supra* notes 208-44 and accompanying text.