FULL ELECTRIC UTILITY OWNERSHIP OF PURPA QUALIFYING COGENERATION FACILITIES: TROUBLE DOWN THE LINE?

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I. INTRODUCTION

American industry wastes tremendous amounts of energy annually as a result of its inefficient use of process heat.[1] In order to utilize this waste heat, Congress enacted section 210 of the Public Utilities Regulatory Policies Act of 1978[2] (PURPA). Section 210 provides incentives for industry to engage in cogeneration—the sequential production of thermal and electric energy.[3] PURPA establishes a

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1. Process heat is the thermal energy expended by industry in its manufacturing operations. Examples of process heat include kinetic energy expended in smelting ore, driving a turbine, or rolling steel. Industry as a whole wastes an estimated one-half of all heat it produces, both in the United States and worldwide. M. CHIOGIOJI, INDUSTRIAL ENERGY CONSERVATION 22 (1979). The waste heat is dissipated into the earth, water, or atmosphere during manufacturing or other processes. *Id.*

Individual industries vary in their effective use of manufactured heat. On a scale where efficiency is measured by the capabilities of currently operating equipment (first law of thermodynamics test), the chemical industry utilizes 50% of available heat; electric power production, 30%; the steel industry, 25%; garbage incineration, 17%; and copper smelting, 12%. *Id.* at 27.

2. 16 U.S.C. § 824a-3 (1982). Congress sought to develop certain types of energy efficiency technologies and alternative energy fuel sources as means to generate electricity. Waste heat was only one of the sources promoted.

3. *Id.* In addition, § 210 promotes a number of alternative energy technologies designated "small power production" facilities as well as geothermal power produc-

framework by which individual entrepreneurs[4] may engage in cogeneration without coming within the jurisdiction of state[5] and fed-

tion. *Id.* § 824a-3 (a). These include facilities fueled by biomass, waste, renewable resources, geothermal resources, or a combination of these fuels. *Id.* § 796(17)(A)(i). The facilities may not be larger than 80 megawatts (mw) capacity. *Id.* § 796(17)(A)(ii). These facilities fall into four categories: 1) solar (radiant energy from the sun used to create electricity with photovoltaic cells), *see* Costello & Rappaport, *The Technical and Economic Development of Photovoltaics*, 5 ANN. REV. ENERGY 336 (1980); 2) wind (wind drives propellers turning a generator), *see* Oppendahl & Tarduno, *Wind Energy Conversion*, 5 HARV. ENVTL. L. REV. 431 (1981); 3) low head hydro (small dams or natural streams turning generator), *see* Erskine, *A Future for Hydropower: Small Dams, Non-Dams*, ENV'T 33-38 (Mar. 1978); and 4) geothermal (ground heat used to produce steam that turns a generator), *see* Note, *Geothermal Resources for the Small Developer*, 3 J. CONTEMP. L. 241 (1977).

4. Persons applying to the Federal Energy Regulatory Commission (FERC) for registration as a qualifying cogenerating facility (QCF) are a highly diverse group. In addition to large industrialists and energy corporations are a number of individuals engaging in what can best be described as "sparking," i.e., operating tiny generating systems and selling the output to the local electric company. *See, e.g.*, Charles Krivanek, 23 F.E.R.C. ¶ 62,062 (1983) (10 kw wind power); Justin W. Whitney, 21 F.E.R.C. ¶ 62,040 (1982) (five kw wind power); Summer House Inn, 20 F.E.R.C. ¶ 62,450 (1982) (100 kw cogeneration).

5. An industry that has committed its private property to the service of the public may be regulated by government in order to ensure the public's receipt of service. Munn v. Illinois, 94 U.S. 113 (1876), is a frequently cited case that confirmed the constitutionality of Illinois' regulations of grain elevators in Chicago. Although both natural monopolies (e.g., municipal sewer system) and competitive industries (e.g., private trucking companies) are regulated, there is growing dissatisfaction with economic regulation of business expressed by both the regulators and the regulated. *See* Strauss, *Regulatory Analysis and Judicial Review*, 42 OHIO ST. L.J. 627 (1981). There is still a case to be made against deregulation, and persons in some regulated industries are strongly opposed to deregulation. *See* Dowd and Burton, *Deregulation is not an Answer for Electric Utilities*, 110 PUB. UTIL. FORT., Sept. 16, 1982, at 21. *But cf.* Berry, *The Case for Competition in the Electric Utility Industry*, 110 PUB. UTIL. FORT., Sept. 16, 1982, at 13.

The history of the regulation of electricity industries is cyclical: there are calls for regulation, intermittent industry dissatisfaction, and then calls for deregulation. Early commercial generation and distribution of power was an area left wide open to private enterprise, and in some parts of the country areas as small as one square block were made service areas for a given utility company by a municipal authority. *See* R. HELLMAN, GOVERNMENT COMPETITION IN THE ELECTRIC UTILITY INDUSTRY 9 (1972). Local government soon realized that more efficient power supply systems than could be effectuated through competition were necessary, and cries for official intervention arose from both ratepayer and supplier. *Id.* at 10. The latter were particularly vociferous as they saw each other swallowed up by larger competitors.

The basic form of electric utility regulation is public or private ownership of generating and distributing facilities monitored by state public utilities commissions. The commissions are responsible for setting allowable rates of return, hearing disputes between the utility and the ratepayer, guaranteeing proper foresight in planning, and

eral[6] electric utility regulations. Although PURPA has caused hundreds of persons to engage in deregulated generation,[7] the overall success of the plan has been limited: substantial available cogeneration capacity remains untapped with no sign of utilization.[8] This lack of development may be blamed partly on the express exclusion of

assuring both the utilities and the public that each will be treated fairly. *See generally* 1 A. PRIEST, PRINCIPLES OF PUBLIC UTILITY REGULATION 25-44, 227-84 (1969). If an electric company normally does not sell to the public as would a non-profit cooperative supplying electric service only to members, it will not be under the jurisdiction of many state utility commissions. *See, e.g.*, Inland Empire Rural Electrification v. Department of Pub. Works, 199 Wash. 527, 92 P.2d 258 (1939). The utility is then self-regulating.

6. Electric utilities are regulated by the FERC pursuant to its authority under the Federal Power Act, 16 U.S.C. §§ 791a-828c (1982). Owners of electric utilities are regulated by the Securities and Exchange Commission (SEC) pursuant to the Public Utility Holding Company Act of 1935 (PUHCA), 15 U.S.C. §§ 79-79z-6 (1982).

The Federal Power Act establishes regulation of the wholesale sale of electric power, and it governs wholesale rates (§ 824e), accounting procedures (§ 825), interconnection of utility grids (§ 824a), and many other facets of utility operation.

As a major piece of New Deal legislation, PUHCA marked the end of unregulated ownership of controlling blocks of utility shares. The Federal Trade Commission had researched abuses by electric utility holding companies and found that many companies: 1) Had issued shares based on paper assets; 2) had extracted unconscionable profits from subsidiaries; 3) were able to control subsidiaries with inordinately low investments; and 4) generally did not take the best interests of the subsidiary into account. 2 A. PRIEST, *supra* note 5, at 507. Because the public need for reliable electric power is highly compelling, Congress required the utilities to register detailed organizational and financial information with the SEC, and disallowed transactions of company shares without SEC approval. 15 U.S.C. §§ 79e-g (1982). Mergers and acquisitions now must be approved by the Commission. *Id.* § 79(j). There are a number of other technical regulations. *See generally* 2 A. PRIEST, *supra* note 5, at 511-22. Presently, there is a movement to modify drastically or repeal PUHCA. *See The Movement to Revise the Public Utility Holding Company Act*, 112 PUB. UTIL. FORT., Dec. 8, 1983, at 39; Hawes, *Public Utility Holding Company Act of 1935—Fossil or Foil?*, 30 VAND. L. REV. 605 (1977).

7. By January 1, 1984, the FERC had certified approximately 430 qualifying cogeneration and small power production facilities pursuant to rules providing for optional certification. 18 C.F.R. § 292.207 (1984). Of that figure, 162 are cogenerating facilities.

8. *See infra* text accompanying notes 134-36. One study estimates that industry will develop between 6,200 mw and 12,800 mw of cogenerated power by the year 1990. RESOURCE PLANNING ASSOCIATES, THE POTENTIAL FOR INDUSTRIAL COGENERATION BY 1990, July 31, 1981, *cited in Public Utility Regulatory Policy Act Amendments: Hearings on S.1885 and S.1966 Before the Subcomm. on Energy Regulation of the Senate Energy and Natural Resources Comm., part 1*, 97th Cong., 2d Sess. 79 (1982) [hereinafter cited as *Senate Amendments*]. That compares unfavorably with estimates of 1985 cogeneration potential of up to 267,000 mw. Williams, *Industrial Cogeneration*, 3 ANN. REV. ENERGY 313, 331 (1978).

electric utilities from full ownership of qualifying cogeneration facilities (QCF)[9] because many potential cogenerators have neither the expertise nor the capital to engage in QCF development.[10] Presently, electric utilities may own no more than fifty percent of a QCF either directly or through a subsidiary.[11]

One method of realizing greater benefit from cogeneration would be to permit electric utilities to wholly own QCFs through PURPA amendment.[12] This Note examines the major issues presented by full utility[13] ownership of QCFs. It analyzes the statutory scheme regarding ownership requirements and the Federal Energy Regulatory Commission (FERC)[14] rules promulgated thereunder. The Note then turns to the potential benefits of such regulatory change, and any detrimental manifestations that might occur. Finally, the Note makes recommendations for suggested change.

II. COGENERATION TECHNOLOGY

The simultaneous production of electricity and some other form of

9. The statute prohibits a person primarily engaged in the sale or production of electric power from owning a qualifying facility. 16 U.S.C. §§ 796(17)(C)(ii), (18)(B)(ii) (1982). Under the FERC rules an electric utility may own no more than 50% of a qualifying facility. 18 C.F.R. § 292.206(b) (1984). *See infra* notes 76-97 and accompanying text.

10. Capital and operating costs of even small cogenerators can be prohibitive. Furthermore, expertise in power generation and distribution is limited to the regulated sector. *See infra* notes 102-13 and accompanying text.

11. 18 C.F.R. § 292.206(b) (1984).

12. Some interested parties believe that the statute does not prohibit full electric utility ownership of QCFs, and that it is within the power of the FERC to bring about a change through rulemaking. *Senate Amendments*, supra note 8, at 30 (statement of Hon. C.M. Butler, Chairman, Federal Energy Regulatory Commission); *id.* at 297 (letter from Frederick L. Weber, Executive Vice President, Edison Electric Institute, to Sen. Gordon J. Humphrey, May 21, 1982); *id.* at 308 (letter from Rita A. Barmann, Director of Congressional Relations, National Association of Regulatory Utility Commissioners, to Marilyn Burkhardt, Counsel, Senate Subcommittee on Energy Regulation, May 3, 1982).

13. For the purposes of this Note, the word "utility" when used alone is to mean "electric utility" unless otherwise noted.

14. The FERC, along with the Department of Energy, is successor to the Federal Power Commission. 42 U.S.C. § 7172 (1982). The jurisdiction extends to oversight of hydroelectric works, generation and transmission of electric power, rates and transport charges for natural gas, regulation of mergers under the Federal Power Act and the Natural Gas Act, and regulations of oil pipeline transport charges. *Id.* The Commission is empowered to make rules and adjudicate disputes, and it exercises both powers broadly. *Id.* §§ 7172(f)-(g).

usable energy (cogeneration), once widely practiced by industry,[15] was abandoned until recently.[16] By using the same combustion for two separate processes, a cogenerator can achieve maximum fuel efficiency.[17] Thus, a cogenerator can produce electricity and a thermal by-product and use little more than the same amount of fuel necessary to produce either type of energy independently.[18]

There are two types of cogenerators—topping and bottoming. The topping cogenerator is a system in which fuel is burned in the production of electricity, and the exhaust is harnessed for a secondary use.[19] For example, in a factory that produces power by operating

15. Industrial cogeneration dates to the 1880s in both Europe and the United States. The need at the time was based in the undeveloped and unreliable condition of electric utilities. OFFICE OF TECHNOLOGY ASSESSMENT, INDUSTRIAL AND COMMERCIAL COGENERATION 3 (1983) (Pub. No. OTA-E-192) [hereinafter cited as OTA].

16. In 1902, of the 2,000 mw capacity on line nationwide, 59.4% were industrial generation, although not necessarily cogeneration. By 1980, total on line capacity was approximately 600,000 mw, of which approximately 2.7%, or 16.2 mw, was of industrial origin. *Id.* at 4.

17. A small cogenerator manufactured by the Fiat Corporation and intended for residential use realizes 90% fuel efficiency as compared with 30% for conventional power plants and 60-65% for conventional boilers. *Cogeneration: Hearings Before the Subcomm. on Energy Development and Applications of the Comm. on Science and Technology*, 96th Cong., 2d Sess. 196 (1980) (testimony of Eduardo Bassignana, Director, Fiat Auto S.P.A/TOTEM). As measured by the second law of thermodynamics ("the ratio of the least amount of energy that could have accomplished a specific task . . . to the amount of energy actually required to perform that task"), cogeneration is 44% fuel efficient when compared with electric production (33%), steel production (23%) and petroleum production (9%). N. DEAN, ENERGY EFFICIENCY IN INDUSTRY 5 (1980). Presumably, if those lower efficiency processes engaged in cogeneration, they would realize considerably greater benefit from their energy dollar.

18. For example, a conventional electric generator produces 600 kilowatt-hours (kwh) of power from one barrel of oil. A conventional steam boiler can produce 8,500 lbs. of process steam from 2 1/4 barrels of oil. A cogeneration system can produce 600 kwh of power and 8,500 lbs. of steam for 2 3/4 barrels of oil. There is thus a net savings of one-half a barrel of oil over separate production of power and steam. OTA, *supra* note 15, at 7.

19. There are several commercial topping technologies currently available. The most common technology is steam turbine topping, consisting of a boiler, turbine, and generator. Fuel is burned, which boils water into high pressure steam. The steam drives the turbine, which in turn is connected to a generator, which produces power. The steam exits the turbine at a reduced pressure and temperature, where it is suited for space heating or industrial processes requiring low pressure steam, such as chemical and paper manufacturing. *Id.* at 122. Steam stopping is the oldest form of cogeneration, and also has the least potential for energy savings. N. DEAN, *supra* note 17, at 135. It is, however, one of the easiest to adapt to coal fuel. *Id.*

Open-cycle combustion turbines are similar to steam turbines, but unlike steam

coal-fired boilers to produce steam for driving a turbine, the factory could use the exhaust steam for purposes such as space heating, industrial process, or for sale.[20] Some electric utilities have engaged extensively in topping cogeneration for many years.[21]

A bottoming cogenerator utilizes exhaust heat from industrial or commercial combustion to drive an electric generator.[22] The heat source may be a kiln, furnace, waste incinerator, or other device, and may burn a wide range of fuels.[23] The heat may drive the generator directly or convert water into steam to drive it.[24] These systems are particularly attractive because of their low operating temperatures[25] and broad applications. Many industries that produce large amounts of heat could begin to produce electrical energy without having to redesign existing plant facilities.[26] The power produced by the industrial cogenerator could be used both to electrify the plant and as a

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turbines they burn fuel within the turbine itself, as occurs with an aircraft engine. The turbine turns a generator, and the exhaust flows into a boiler where it boils water into steam. The systems must run on either oil or gas, but may be converted from one to the other in only one day. OTA, *supra* note 15, at 126. They are generally more efficient than steam turbines and have low pollutant emissions. N. DEAN, *supra* note 17, at 135.

Closed-cycle combustion cogenerators operate by heating a medium (air or helium) in a closed space and directing the hot gas into a turbine. The turbine drives a generator which produces power. The exhaust gas runs through a boiler and produces steam, and the gas circulates back into the turbine. OTA, *supra* note 15, at 127-28. Closed-cycle systems offer greater efficiencies at partial load than open systems. *Id.*

A diesel cogenerator is a diesel fueled reciprocating internal combustion engine with a drive shaft that turns a generator and with a cooling system that generates steam. The next generation of diesel cogenerators will offer 50% more power per cylinder than current models. *Id.* at 131-32.

20. A more ambitious use would be for district heating, in which exhaust steam from power generation is pumped through underground steam lines to provide space heating for neighboring buildings. District heating is widely used in Europe, and to a lesser extent in the United States.

21. Consolidated Edison Co. in New York has operated a large cogenerating district heating system since the nineteenth century. R. MEADOR, COGENERATION AND DISTRICT HEATING 13 (1981). *See generally District Heating and Cooling: Hearings Before the Subcomm. on Energy Development and Applications of the House Comm. on Science and Technology*, 97th Cong., 1st Sess. 154 (1981).

22. Bottoming cogenerators have the advantage of not requiring additional fuel. They use exhaust gas or steam from primary processes to run a turbine, which turns a generator. N. DEAN, *supra* note 17, at 140.

23. *See* OTA, *supra* note 15, at 133-37.

24. *Id.* at 133-34.

25. Units operate between 200° and 600° F. *Id.* at 135.

26. *Id.* at 180.

commodity to sell back to the local utility.[27]

Some suggest that cogeneration has tremendous potential. One federal agency foresees a potential cogeneration capacity of two hundred thousand megawatts (mw) by the year 2000[28] or almost one-third of all existing generating capacity on-line in 1980.[29] While practical considerations might restrain industry from realizing this total capacity,[30] rising energy costs[31] and the realization that cogeneration may be a commercially attractive alternative to utility-purchased power may prompt some industrialists to regard cogeneration as a viable investment.

Industrial cogeneration is perhaps America's single largest readily available alternative energy source.[32] One commentator suggests that if industrial manufacturers were to begin cogenerating, the nation would save up to five million barrels of oil a day. This amounts to thirty-two percent of national oil consumption and fifteen percent of total national energy consumption.[33] Furthermore, if industry invested twenty percent more capital into cogeneration, the nation

27. Section 210 does not permit QCFs or small power production facilities "to make any sale for purposes other than resale," and it prohibits the FERC from making rules authorizing non-resale transactions. 16 U.S.C. § 824a-3(a) (1982). Consequently, those facilities may not sell power directly to industrial, commercial, rural, or residential consumers. This scheme retains the electric utilities' monopoly on distribution and minimizes redundancy in the grid system. It may also have safety implications.

It is not clear why large industrial cogenerators should not sell power directly to selected consumers such as other large industries. Possible benefits include lower power costs through competition because rates would be based on true market forces rather than the stiff avoided cost system. *See infra* note 68. The detriment would be the direct loss to the utility of additional customers because the utility could no longer serve as middleman.

28. OTA, *supra* note 15, at 10.

29. Total installed U.S. generating capacity in 1980 was 619,000 mw. *Id.*

30. *See infra* notes 102-25 and accompanying text.

31. Although fuel costs have fluctuated in recent years, there is a general trend toward price increases. ENERGY INFORMATION ADMINISTRATION, 1982 ANNUAL ENERGY OUTLOOK xvi. Between 1975 and 1980 gas prices rose $1.41 per million BTUs for industrial users. Prices will rise an additional $2.72 per million BTUs by 1985, and will be $4.33 above 1980 rates by 1990. *Id.* at xvii. Low grade industrial oil prices rose $1.03 between 1975 and 1980 to $5.14 per million BTU, and the estimated 1990 price is $6.95 per million BTU. *Id.*

32. Cogeneration would tap the tremendous waste in industrial process heat production, which is self-contained. Unlike hydro, wind, or solar energy sources, waste heat is easily tapped and requires no new technology.

33. N. DEAN, *supra* note 17, at 144.

might save nineteen billion dollars by the mid-1980s[34] Although other alternative energy sources[35] may contribute to energy savings, they could not equal the potential power attainable by industrial cogeneration without a significantly greater impact on the landscape and the environment.[36]

III. ELECTRIC UTILITY REGULATION AND COGENERATION

A. *Electric Utility Regulation*

Federal and state authorities have regulated the generation and distribution of electric power since the early twentieth century.[37] Regulation precipitated from the confusion that accompanied the application of laissez-faire competition to the distribution system.[38] Without centralized planning, competing firms created the danger of utility wires crisscrossing a service area and the possibility of leaving portions of the population without service when the power company to which they subscribed went out of business.[39] Legislators saw competition as creating redundancy rather than efficiency, and ruled that in order to protect the public's welfare, government would replace electricity production competition with a system authorizing the government to grant a franchise to one company to supply the needs of the community.[40]

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34. DOW CHEMICAL COMPANY, ENERGY INDUSTRIAL CENTER STUDY 273 (1975) (available from the National Technical Information Service, No. PB 243-823).

35. *See supra* note 3.

36. Each alternative energy source takes its toll on the environment. Utilizing solar energy requires large photovoltaic panels or mirrors. Wind power requires windmills to be set atop hills or in other unobstructed (and thus visible) locations. Hydro electric power requires the construction of dams, with the accompanying detriments.

37. *See supra* notes 5-6.

38. A. FINDER, THE STATES AND ELECTRIC UTILITY REGULATIONS 3-4 (1977).

39. *Id.*

40. *Id.*

Government regulation of electric utilities is often justified by the industry's tendency toward natural monopoly. 2 A. KAHN, THE ECONOMICS OF REGULATION 117 (1971). Kahn summarizes the essence of the natural monopoly:

> The critical—if properly defined—all-embracing characteristic of natural monopoly is an inherent tendency to decreasing unit costs over the entire extent of the market. This is so only when the economies achievable by a larger output are internal to the individual firm—if, that is to say, it is only as more output is concentrated in a single supplier that unit costs will decline.

Id. at 119. The "principle source" of this phenomenon is the need for high fixed costs

Action on the federal level came during the depression of the 1930s.[41] The Federal Power Commission (now the FERC) directly regulated electric utilities under the Federal Power Act.[42] Utility holding companies[43] came under the domain of the Securities and Exchange Commission pursuant to the Public Utility Holding Company Act of 1935.[44] Congress intended that these laws would prevent monopolist utilities from gouging the public and would guarantee a reliable source of electric power for the nation.[45] These laws, however, produced an additional effect: coupled with state regulation, they stifled non-utility electric power generation.[46] The laws swept so broadly that any person or organization engaged in electricity production for sale came within the regulation's coverage regardless of its primary business.[47] Compliance with these laws is an expensive and complicated endeavor.[48]

The regulated industries themselves engaged in practices meant to forestall any competition in the field of electric power production,[49]

(for generating and transmitting equipment) regardless of the number of units sold. *Id.* at 120. Consequently, "average costs per unit decline in inverse proportion to the number of units sold." *Id.*

Another factor in the tendency toward natural monopoly is economies of scale. *Id.* The monopoly remains efficient "as long as plants constructed for higher levels of output will have lower average costs than smaller plants, or where it will cost less for an existing supplier to add a given amount of capacity to its existing plant than for a new supplier to supply it." *Id.* Finally, "variability in demand" may be reduced if a single supplier serves more customers over a larger region; the result should be lower average costs for the utility. *Id.* at 123.

41. *See supra* note 6.

42. *Id.* The FERC regulates certain activities and sales, although the states continue to regulate prices for residential sales.

43. 15 U.S.C. § 79b(a)(7) (1982) defines a public utility holding company as any company that directly or indirectly owns 10% or more of the voting securities of a public utility company.

44. *See supra* note 6.

45. PUHCA sought to prevent abuses by holding companies. Among company abuses were the issuance of unsound securities, misdealings with subsidiaries, the control of subsidiaries through small investment, and the expansion of the holding companies when not in the best interests of ratepayers. 2 A. PRIEST, *supra* note 5, at 507. The United States Supreme Court upheld the constitutionality of the statute in Electric Bond & Share Co. v. SEC, 303 U.S. 419 (1938).

46. By 1980, consumption accounted for 97.3% of the available electricity capacity. OTA, *supra* note 15, at 4.

47. N. DEAN, *supra* note 17, at 158-64.

48. *Id.* at 160.

49. These activities included refusal to permit interconnection, refusal to allow

even in areas where individuals were permitted to operate.[50] If an industrial enterprise sought to supply its own electric needs, it could expect little assistance from the local utility.[51] The electric company would refuse to supply backup power if the independent facility failed, or else it would offer backup power at exorbitant rates.[52] The utility would refuse to purchase surplus power, or would refuse to permit interconnection by the individual into the utility grid.[53] If the utility agreed to purchase surplus power, the rates often were unconscionably low.[54]

In the regulated environment of electric power production and distribution, the development of small scale alternative energy facilities would have been impossible.[55] Persons seeking to guarantee power for themselves would have been rebuffed by utilities, and persons seeking to generate power for sale would have been trapped in a forest of regulatory red tape. If Congress wanted to promote alternative energy production on a grassroots level, it would have to create an attractive environment for entrepreneurs by removing barriers to market entry.

B. *PURPA Section 210*

Section 210 of PURPA[56] encourages cogeneration and alternative energy small power production by removing regulatory and institutional barriers to non-utility generation for certain qualifying parties.[57] It provides a framework by which these parties can

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feedback of power into the utility grid, high prices for backup power, low prices for power purchased from private producers and others. Gentry, *Public Utility Participation in Decentralized Power Production*, 5 HARV. ENVTL. L. REV. 297, 316 (1981). *See generally* Cross, *Cogeneration: Its Potential and Incentives for Development*, 3 HARV. ENVTL. L. REV. 236, 242 (1979).

50. An industry that subjected itself to regulation would still have utility-made barriers with which to cope.

51. *See supra* note 49 and accompanying text.

52. *Id.*

53. *Id.*

54. *Id.*

55. *See* Preamble to FERC Final Rules concerning Small Power Production Facilities and Cogeneration, 45 Fed. Reg. 17,959 (1980).

56. 16 U.S.C. § 824a-3 (1982).

57. *See generally* Lock, *Encouraging Decentralized Generation of Electricity: Implementation of the New Statutory Scheme*, 2 SOLAR L. REP. 705, 711-15 (1980).

interconnect[58] with the local utility grid and buy and sell power to that utility.[59] Approved interconnection exempts the qualifying generator from most federal and state regulations relating to power production[60] and ownership of electricity producing entities.[61] The utilities must accept the existence of the unregulated power production and deal fairly with the producers.[62] Section 210 instructs the FERC to administer the statute and further its purposes[63] by making rules for application by state public utility commissions.

Congress also outlined rates for the purchase and sale of power by utilities.[64] It emphasized strongly that all such purchases and sales must be just and reasonable to electricity consumers[65] and to the public.[66] Furthermore, such rates may not discriminate against any qualifying cogenerators or small power producers.[67] Electric utility purchase rates may not exceed "the incremental cost of alternative electric energy."[68] Consequently, a public utility commission[69]

58. Section 824a-3 requires the FERC to promulgate rules "to encourage cogeneration and small power production." The interconnection rules require the utility to "make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales. . . ." 18 C.F.R. § 292.303(c)(1) (1984). "An interconnection is a physical connection that allows electricity to flow from one entity to another." FERC v. American Elec. Power Serv. Corp., 103 S. Ct. 1921 (1983). In *American Electric Power*, the Supreme Court held that the FERC rules under § 210 were not an abuse of discretion. In terms of interconnection, the Court upheld the FERC rules that did not require an evidentiary hearing between the qualifying facility and the utility before interconnection. The Court noted correctly that to provide for such hearings each time a QCF requested interconnection would seriously impede congressional intent of expeditiously developing § 210 capacity. *Id.* at 1931-33.

59. 16 U.S.C. § 824a-3(a) (1982). FERC rules require utilities to buy all power the QCF has to offer and to sell to the QCF its requirements. 18 C.F.R. §§ 292.303(a), (b) (1984).

60. 16 U.S.C. § 824a-3(e) (1982).

61. *Id.*

62. *Id.* §§ 824a-3(b), (c).

63. *Id.* § 824a-3(a).

64. *Id.* §§ 824a-3(b), (d).

65. *Id.*

66. *Id.*

67. *Id.*

68. *Id.* § 824a-3(b). PURPA § 210 limits the payments by electric utilities to cogeneration and small power production facilities for power produced by those facilities to no more than the incremental cost to the purchasing utility of alternative power. *Id.* §§ 824a-3 (b), (d). It defines "incremental cost of alternative" energy as being the amount it would have cost for the utility either to generate the power itself or purchase the power from some other source, such as a neighboring utility. *Id.*

charged by the FERC with establishing these "avoided cost" rates can never require an electric utility to pay more for power than it

§ 824a-3(d). FERC's rule, 18 C.F.R. §§ 292.304(b)(2), (b)(4), requires utilities to purchase power at rates "equal" to the incremental, or avoided, cost. The United States Supreme Court upheld these rules in *American Electric Power. See supra* note 58.

The avoided cost formula itself causes much uncertainty among regulated utilities, public utility commissions, and facilities. The primary questions concern what factors should be included in the avoided cost calculation. Variables used by state commissions for the calculation include energy costs and costs saved by reduced new construction requirements (*Re* Connecticut Light and Power, 41 P.U.R. 4th 1 (Connecticut Dep't of Pub. Util. Control 1980)), the presence of a facility's contractual obligation to supply a given amount of power, i.e. "firmness of capacity" (*Re* Rulemaking Proceeding for Consideration of Cogeneration and Small Power Production, 40 P.U.R. 4th 563 (Idaho Pub. Util. Comm'n 1980)), and a utility's annual carrying charge for keeping the facility on line (170 IND. ADMIN. R. § 4-4-5 (Burns 1982)). Indiana's public utility commission has created the following formula for calculation of avoided cost:

$$P_j = \frac{\sum_{i=1}^{nj} i_j}{n_j}$$

P_j = full unadjusted rate for purchase of energy in the j^{th} period.

i_j = expected fuel and associated variable operating costs for the most expensive unit on line in the i^{th} hour of the j^{th} period, derived from recent data.

n_j = number of hours in the j^{th} period.

Id. § 4-4-8.

Choosing the source of the alternative power to be used as an avoided cost standard is critical. In Appeal of Granite State Elec. Co., 121 N.H. 787, 435 A.2d 119 (1981), the New Hampshire Supreme Court struck down state public utility commission rules that calculated avoided costs based on the newest oil fired generating plant in the state for every other utility in the state. By this calculation, Granite State paid 8.2¢ per kilowatt hour of power purchased from small power facilities. It claimed that since it had an excess of capacity, it could generate the same power for 7.7¢ per kilowatt hour. The court held that the PUC had insufficient evidence with which to make the blanket avoided cost determination, and that the "proxy" plant method was illegal unless all utilities agreed to be measured in relation to that single plant. *Id.* at 792, 435 A.2d at 122.

Statewide avoided cost rates are currently in effect in some states. *See* Lock, *Statewide Purchase Rates Under Section 210 of PURPA*, 3 SOLAR L. REP. 419 (1981).

69. *See generally* OTA, *supra* note 15, for purchase rates for power. Larger cogenerators may (and often must) contract individually with utilities for purchase rates.

could have purchased from another source or generated by itself.[70]

Section 210 exempts all QCFs and certain types of small power producers[71] from most regulations under the Federal Power Act, and from state laws regulating electric power rates and financial and organizational requirements of utilities.[72] Section 210 does not, however, exempt QCFs from state regulations made pursuant to FERC edict,[73] from federal law relating to interconnection with utilities wheeling,[74] or from certain licensing requirements.[75]

C. *PURPA Section 201*

In section 201,[76] Congress outlines the types of generating capacity that enjoys benefits under the section.[77] It divides the technologies into two categories, cogeneration and small power production, although the basic requirements for both groups are substantially the same. For both categories, Congress ordered the FERC to promulgate rules for qualifying facility size, fuel use requirements, efficiency, and ownership criteria.[78]

The statute defines QCFs as cogenerators that produce electric en-

70. Nevertheless, higher-than-avoided cost payments are possible. *See supra* note 68.

71. Congress established size limitations for qualifying small power production facilities, but not for cogenerators. Small power producers at any given site may not be larger than 80 mw. 16 U.S.C. § 796(17)(A)(ii) (1982). The FERC rules define "site" as an area "within one mile of the facility for which qualification is sought." 18 C.F.R. § 292.204(a)(2) (1984). The rule for small hydro-electric power applies to facilities that operate off the same impoundment. *Id. See generally* FERC Rules Concerning Cogeneration and Small Power Production, 45 Fed. Reg. 17,959, 17,965 (1980).

72. *See generally* 64 AM. JUR. 2D *Public Utilities* §§ 88-100 (1972) (description of these regulations).

73. 16 U.S.C. § 824a-3(e)(3)(A) (1982).

74. *Id.* Section 824i gives the FERC power to issue orders concerning interconnection and purchase and sale between QCFs and utilities. Section 824j permits utilities or QCFs to petition the FERC to "provide transmission services" to the applicant. The statute promotes efficiency by requiring utilities to "wheel" power between separate utility service areas. Previously, utilities located between service areas would refuse to act (literally) as middleman in this scheme.

75. *Id.* § 824a-3(e)(3)(C) (1982).

76. *Id.* §§ 796(17), (18) (1982) (codified in pertinent part).

77. Congress amended PURPA in 1980 to include geothermal small power production. 94 Stat. 770 (1980).

78. 16 U.S.C. §§ 796(17)(C)(i), (18)(B)(i) (1982).

ergy and some form of useful energy, such as steam or heat.[79] In order for a QCF to qualify for section 210, it must comply with technical rules put forth by the FERC and state public utilities commissions.[80] The QCF must not be "owned by a person . . . primarily engaged in the generation or sale of electric power" outside of the small power facility itself.[81]

The section 201 requirements are ambiguous because they do not define the word "own." While it is clear that the limitation is aimed at regulated and self-regulating[82] electric utilities, the word "own" can take on widely varying interpretations. Under a strict reading, section 201 might prohibit electric utility ownership of QCFs altogether, because any equity interest is a form of ownership. Read more broadly, ownership may be defined as full equity interest. Under that interpretation, anything short of full equity interest would fall outside of the prohibition. Consequently, an electric utility might possess ninety-nine percent of the equity in a QCF, but still not "own" it. The utility would be merely a partner to ownership. Finally, "ownership" may be defined as direct ownership of generating properties. Therefore, indirect ownership through corporate subsidiaries would fall outside of the statutory prohibition.[83]

Section 201's legislative history does not illuminate these ownership requirements. The conference report on the bills that became PURPA[84] is no more explicit than the statute itself. The report interprets the proper test as prohibiting an entity that is primarily engaged in regulated power production from owning a QCF.[85] This standard

79. *Id.* §§ 796 (18)(A), (B)(ii).

80. *Id.*

81. *Id.* §§ 796 (17)(C)(ii), 18(B)(ii).

82. A self-regulating utility is one that is not under the jurisdiction of a public utility commission. *See supra* note 14.

83. A further interpretation of § 201's ownership requirement is ownership as "control." Rather than looking to percentages of equity interest, such an analysis would look to the quality of that interest, i.e., how much power the utility has in decision-making. A scenario in which a utility comes within 50% while still exercising voting control would be where two parties each own 49% of the shares of a QCF and a utility owns 2%, and each share has one vote. When the parties are split on an issue, the utility casts the deciding vote. If one of the 49% shareholders is the utility's "angel," the utility always could maintain control. Such an arrangement could provide the utility with leverage the FERC sought to forbid under its rules.

84. H. CONF. REP. 95-1750, 95th Cong., 2d Sess. 78, *reprinted in* 1978 U.S. CODE CONG. & AD. NEWS 7797, 7822-24.

85. *Id.* at 7823.

does permit a utility to own directly a percentage of a QCF.[86] It, however, does not define the nature of non-utility QCF ownership entities. Presumably, such an entity can be a wholly owned corporate subsidiary of an electric utility.[87] It will pass the conference report's test as long as the subsidiary's stated purpose is to engage in a business other than regulated electric power production because the utility will not own the QCF, but only shares in a subsidiary corporation. A stricter approach would take into account any direct or indirect ownership interest in an electric utility when determining section 210 qualifications.

The ambiguity in section 201 and its legislative history may be the result of a legislative intent to give the FERC maximum freedom in interpreting QCF ownership requirements.[88] The FERC used this ambiguity as license to establish rules varying substantially from the aforementioned plain meaning analyses.

D. *FERC Rules under Section 201*

The FERC rules interpreting section 201[89] take a middle view concerning regulated electric company ownership of QCFs. The rules do not prohibit those companies from owning QCFs, but limit their interest in them to no more than fifty percent of outstanding equity.[90] This "fifty percent rule" applies to both direct and subsidiary ownership.[91] Thus, the FERC will not look to the owner of record of QCF assets, but will look "upstream" in order to determine where final decision-making control lies.[92] A restricted person, therefore, may

86. *Id.*

87. *See supra* notes 82-83 and accompanying text.

88. Alternatively, the ambiguity may have resulted from the inability of opposing congressional factions to decide whether or not to permit electric utilities to own fully QCFs. Whether such disagreement actually demonstrates an affirmative intent is questionable.

89. 18 C.F.R. §§ 292.101 -.602 (1984).

90. *Id.* § 202.206(b).

91. *Id.* In its comments accompanying the rule, the FERC addressed the possibility that PURPA would permit several utilities to own jointly the shares of a corporation owning a cogenerator without violating the QCF ownership requirements. It stated "that the thrust of section 201 of PURPA is to limit the advantages of qualifying status to cogeneration and small power production facilities which are not owned primarily by electric utilities *and their subsidiaries*." 45 Fed. Reg. 17,970 (1980) (emphasis added).

92. *See supra* note 85.

own fifty percent of a QCF, fifty percent of a company which owns all of a QCF, or all of a company which owns fifty percent of a QCF, but no other combination.

In comments accompanying the ownership regulations, the FERC justified its restrictive interpretation of section 201 by identifying what it called a "thrust" in PURPA that will exclude utilities from QCF benefits.[93] The limitation is not based on those persons' monopoly power, but on the concern that "such companies would divert scarce capital resources or convert existing jurisdictional facilities from regulated to unregulated qualifying facilities."[94] The comments go no further in explaining the FERC's restrictive interpretation, and the rationale stated seems unsatisfying. If the FERC is indeed concerned that regulated electric utilities will neglect their primary duties for which the government has granted an exclusive franchise, then it is anomalous that the Commission has granted nongenerating regulated utilities the ability to own fully QCFs.[95] Apparently, the FERC is not concerned sufficiently with the possibility of investment distortion in non-electric utilities to limit those utilities' investment patterns, although it clearly has jurisdiction to do this.[96] Without adequate explanation of where the FERC located Congress' "thrust" in PURPA, the Commission's rationale is open to challenge.[97]

E. *QCF Development after PURPA*

PURPA and the FERC rules clearly have sparked interest in QCF development. By April 1982, the FERC had received applications for over three thousand mw of cogenerated capacity, sixty percent of which consisted of new installations.[98] Despite this early flurry of

93. *See supra* note 91.

94. 45 Fed. Reg. 66,788 (1980).

95. 45 Fed. Reg. 52,779 (1980). For example, natural gas utilities are not restricted in QCF ownership. Similarly, no telephone companies are restricted, although none are cogenerating. There is really no reason to believe that one of these utilities would be less likely to divert funds from its regulated to its unregulated business, particularly if the unregulated business is profitable.

96. *See supra* note 14.

97. Presently, no one has challenged the § 201 rules in court. If the electric utility industry had intended to challenge them it probably would have done so. Because of the broad discretion the Supreme Court gave the FERC in *American Electric Power*, *supra* notes 58 & 68, the utilities probably would be unsuccessful.

98. *Senate Amendments*, *supra* note 8, at 78 (statement of Edison Electric Institute). By January 1, 1984, the FERC had granted 162 applications for certification as a qualifying cogeneration facility, and had denied only two applications. Mercy

activity, and notwithstanding the relatively brief period that the regulatory mechanisms have been in place, it is becoming increasingly clear that the technical potential for QCF power and the actual portion that industry is likely to realize are widely divergent.[99] Business and industry are not taking advantage of all available opportunities at present and there is reason to suspect that the factors responsible for the constraint on development will not diminish over time.[100] Although a "wait and see" attitude[101] may allow persons who are beyond the scope of the "primarily engaged" test as interpreted by the FERC to maximize QCF potential on their own, the following reasons for their nonmaximization of potential would lead to the opposite conclusion.

1. Finite Capital

Cogeneration facilities cost between $350 and $1,600 per kilowatt of generating capacity.[102] A moderately sized QCF requires a minimum initial investment of between $5.25 million and $24 million, not including cost of additional steam lines, interconnection and other items.[103] Marginal operating costs also can be high.[104] Many indus-

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Hosp. and Medical Center, 18 F.E.R.C. ¶ 61,128 (1982) (denial based on failure to satisfy efficiency standards); Granite City Steel Div., Nat'l. Steel Corp., 14 F.E.R.C. ¶ 61,098 (1981) (denial based on applicant's erroneous interpretation of "cogeneration facility").

99. *See infra* text accompanying notes 134-36.

100. *See infra* notes 102-22 and accompanying text.

101. The California Public Utilities Commission has adopted this view. *See The Utility Role in Cogeneration and Small Production: Hearings on H.R. 2876 and H.R. 2992 Before the Subcomm. on Energy Conservation and Power of the House Comm. on Energy and Commerce*, 97th Cong., 1st Sess. 450-51 (1981) [hereinafter cited as *House Amendments*] (statement of Barbara Barkovich, Director of Policy and Planning, California Public Utilities Commission); *id.* at 186-208 (statement of Michael J. Zimmer, Washington Counsel, Cogeneration Coalition, Inc.).

102. OTA, *supra* note 15, at 9. Prices vary according to unit capacity and technology type, and there is substantial overlap between technologies. The least expensive unit is diesel topping, and the most expensive is closed-cycle ("organic") bottoming.

103. This auxiliary noninterconnection equipment includes high pressure steam equipment, piping, and water softeners. These supply a relatively constant steam flow of 50,000 pounds of steam per hour at 400-500 psi. N. DEAN, *supra* note 17, at 142-43. Interconnection costs vary with generator size. The cost per kilowatt hour capacity increases with every decrease in size of unit output. A 20 mw system will cost $35 per kw/hr to interconnect, and a two kw system will cost $1,328. OTA, *supra* note 15, at 157.

104. *Id.* at 121. Costs range from $.26-3.30 per kw/hr annual fixed costs (fuel cell topping) to $6-8 kw/hr annual fixed costs for diesel topping.

tries may be unwilling to place such large investment into secondary processes, preferring instead to invest the funds into their primary processes.[105] Although federal and state law provides a number of financing programs[106] and tax incentives, the industrial manager ultimately must rely on his desire to commit substantial amounts of resources into what is to him only a supplementary business venture. Many basic industries that generate substantial amounts of heat are unable to retool primary processes, let alone invest in diversified holdings.[107] In short, the primary consideration for most managers is the financial health of the company.

2. Limited Expertise

Persons who are capable of operating generating equipment are not readily available in the unregulated sector. This is so because technical expertise in electric power generation traditionally has been concentrated in the regulated industries. Central station generation has decreased the number of generating facilities, which has led to requirements of fewer persons necessary to operate the equipment. Although cogenerators are not always highly sophisticated, capital costs are sufficiently high that an industrialist would not want to install capacity absent assurance that qualified technicians were readily available.

Although cogeneration once was widely adopted in industry,[108] at least a generation has passed since industry became reliant on central

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105. *Senate Amendments*, *supra* note 8, at 66-68 (statement of Ralph C. Mitchell III, Vice President, Conservation and Renewable Resources, Arkansas Power & Light Co.); *id.* at 69 (statement of Frederic E. Greenman, Vice President and Associate General Counsel, New England Power Co.) ("The lesson that we learned was clear. Non-utilities are reluctant to invest in cogeneration projects. They are uncomfortable putting money into projects that are foreign to their area of expertise.").

106. *See* OTA, *supra* note 15, at 105. A 10% Energy Tax Credit expired on Dec. 31, 1982. *See* I.R.C. § 46(a)(2)(C)(i) (1982).

107. This condition results from greater professional opportunities in newer areas of high technology such as the microprocessing industry. Recently, students have begun to enter the area of power distribution, which interest should be furthered by congressional entry into cogeneration legislation. Telephone interview with Walter Kahn, Professor of Electrical Engineering, The George Washington University (May 16, 1984). *See generally* Morgan, *Electric Power Engineering Education National Trends*, E-21 IEEE TRANSACTIONS ON EDUCATION 91 (1978).

108. *See supra* notes 15-16 and accompanying text.

station power.[109] Consequently, industry may be unfamiliar with the function and operation of the technologies involved. A business may be unwilling to permit an unfamiliar piece of hardware on its plant premises that may increase costs and become integrally tied to plant operations. Decision-makers may perceive that if the cogenerator fails, thermal operations must halt until the cogenerator is repaired.[110] While this scenario is possible, sound facility design will enable generation and thermal production to be wholly unrelated.[111] Finally, a company may be unwilling to engage in an activity that can raise its insurance rates and lead to greater potential tort liability.[112]

3. Unacceptable Return on Investment

Many industries require diversified investments to yield a twenty-five to thirty percent investment return.[113] The return must be at least as high or higher than a company's investment in its primary business. Unfortunately, many applications of cogeneration may be unable to provide a rate of return sufficiently high to meet that

109. Industrial self-generation has provided less than 10% of total capacity in the United States since the late 1950s. OTA, *supra* note 15, at 4.

110. This may be the case with most topping cogenerators, where process heat is a by-product of power generation. Industries that plan to cogenerate as an ancillary investment and use topping technology should provide for a by-pass system with which process steam output will not be interrupted by generator failures. Industries that plan to cogenerate as an ancillary investment and use topping technology should provide for a by-pass system with which process steam output will not be interrupted by generator failures.

111. Bottoming cogenerators, where power production operates off waste heat, should be relatively easy to build so that power production and thermal production are separable.

112. A utility worker can be injured while performing line repairs if the cogenerator continued to feed the grid after the line worker thought that he had disconnected all power sources. It is likely that most interconnecting utilities will require a cut-out switch accessible by the utility in order to avoid this type of accident.

Additionally, a QCF could cause damage to the utility grid if the facility malfunctions. One utility provides system protection by requiring: 1) Installation of circuit breakers that automatically disconnect the QCF from the grid if utility feed is lost; 2) calibration by the utility of all protective relay settings; and 3) a disconnect switch within the exclusive control of the utility. UNION ELECTRIC COMPANY, ELECTRIC POWER PURCHASES FROM QUALIFYING FACILITIES 2-3 (Feb. 14, 1983).

113. *The Potential for Industrial Cogeneration Development by 1990, cited in Senate Amendments*, *supra* note 8, at 96. One utility found that industry requires cogeneration to return a minimum of 25% on invested capital. *House Amendments*, *supra* note 101, at 39 (statement of Edison Electric Institute).

standard.[114]

4. Regulatory Uncertainty

All industrial enterprises are subject to extensive government regulation in many facets of operation. After years of compliance an enterprise becomes familiar with the intrusion, but not comfortable. Potential enterprises are reluctant to engender additional and unfamiliar regulations. QCF ownership is subject to regulation even though PURPA attempts to eliminate as much regulation as possible.[115] Thus, while an industry-owned QCF is not subject to rate regulation, it must abide by efficiency, interconnection, safety, reliability, and fuel use standards.[116] While larger potential QCFs may be able to pay for extensive legal and technical advice concerning these regulations, these costs can be unacceptably high to small and moderately sized firms.

The stability of purchase rates is also of concern to the potential cogenerator. Avoided cost-based purchase rates are regulated by state public utility commissions (PUCs),[117] and these rates change along with fluctuations in market rates for power.[118] Avoided cost rates that are profitable at the inception of a QCF project may become unacceptable after the unit comes on line and rates change. While risk inheres in any capital investment, political factors in PUC ratemaking[119] may discourage industries that are unfamiliar with

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114. Because it is not possible to gauge potential rates of return in all situations, pay back rates vary with each projection. The Dow Chemical Company forecasts that a steam turbine with a 400,000 lbs./hr. steam load could earn a pre-tax pay back of 20%. N. DEAN, *supra* note 17, at 200 (quoting DOW CHEMICAL COMPANY, *supra* note 34). An oil-fired boiler with gas turbine topping cogeneration could earn 25%. *Id.* at 200-01. A different study projects steam turbine topping to yield 7% to 27%, gas turbine 25% to 39%, diesel topping 21% to 23%, and bottoming cycle approximately 22%. *Id.* at 201.

Businesses sometimes require extraordinary rates of return on subsidiary investments. For example, a cement manufacturer decided not to invest in a 4.7 mw bottoming cogenerator because the system could only offer 22% pay back even though the manufacturer's usual rate of return on investment was 15% *Id.* One study determined that it would take a 32% rate of return in order to get 80% of potential cogenerators to build facilities. *Id.*

115. *See supra* notes 56-63 and accompanying text.

116. *See supra* note 78 and accompanying text.

117. *See supra* note 63 and accompanying text.

118. *See supra* note 69.

119. *See generally* 1 A. PRIEST, *supra* note 5, at 45-138. For an enlightening view of the most political aspect of ratemaking, the ratemaking hearing, see Jacobs, *Utility*

regulated pricing. Similarly, non-electric utilities may be unfamiliar with the cycles of power industry rates.

5. Instability of Fuel Prices

Avoided cost rates are tied to the price electric utilities must pay for either purchased or self-generated power.[120] These rates depend to a great extent on fuel costs. A QCF using a fuel differing from that used by the electric utility with which it is interconnected is thus at risk of financial loss if its own fuel costs are higher than the utility's costs. For example, a diesel cogenerator interconnected with a coal-fired utility will lose money in its generation business if its marginal fuel costs are higher than the utility's avoided costs. In this instance, a long-term rise in world petroleum prices will render power generation unprofitable.[121]

6. Environmental Regulations

Federal and state air quality standards limit the quantity of pollutants an industrial operation may emit.[122] An industry's available license to pollute is thus as finite and as valuable a resource as land or capital. Because all forms of cogeneration will introduce pollutants into the environment and a portion of that amount is attributable to electric power production rather than to primary process, a potential cogenerator must decide whether available pollution margins should be dedicated to power production. Many firms may choose to save these units for primary business purposes.

F. *Electric Utility Industry QCF Joint Ventures*

The FERC realized that industry would face the aforementioned barriers to cogeneration when it introduced the fifty percent ownership rule. Apparently, the Commission intended for utilities to provide technical and management expertise, and for the nonutility to supply capital, land, and a heat source. Theoretically, such joint ventures appear sound.

Rate Hearings are Sometimes Lively and Always Complex, Wall St. J., Apr. 1, 1974, at 1, col. 6, *reprinted in* T. MORGAN, ECONOMIC REGULATION OF BUSINESS 215-18 (1976).

120. *See supra* note 68.

121. *See supra* note 31.

122. *See generally* 1 F. GRAD, TREATISE ON ENVIRONMENTAL LAW § 3.03 (2d ed. 1978).

In practice, utilities and industry have encountered difficulty in carrying out the joint ventures, largely because of lack of industry involvement.[123] Several utilities have found only one or two industrial partners in their service areas, even when those areas contained hundreds of steam users.[124] The main reasons given by the nonconforming industries for their nonparticipation were the lack of capital and the undesirability of entering operations outside of their primary line of business.[125]

The fifty percent rule also has limited the types of industries with which a utility will seek to form a partnership. Utilities require a QCF to have a large steam requirement[126] in order to produce a profitable return. A utility service area may contain only a few large steam users but a greater number of smaller users. Recent history reveals no one user to be developing smaller QCF potential.[127] The smaller thermal users are not likely to become QCFs themselves,[128] therefore, the potential capacity is wasted.

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123. *See supra* note 105.

124. For example, Arkansas Power commissioned a study of 1,500 oil- and gas-fired steam producers and found at least 35 producers which were "prime candidates" for cogeneration. Of those 35, the utility found none, with the possible exception of two paper product companies, which was likely to invest in cogeneration. *Senate Amendments*, *supra* note 8, at 67 (statement of Ralph C. Mitchell III, Vice President, Conservation and Renewable Resources, Arkansas Power and Light Co.). New England Power Company undertook a similar study and achieved similar results. *Id.* at 68-69 (statement of Frederic E. Greenman, Vice President and Associate General Counsel, New England Power Co.). New England Power had planned to build a 15 mw wood-burning cogenerator but had great difficulty finding a partner. *Id.* The utility finally located a partner, but only because the partner's corporate parent was heavily involved in the energy industry. *Id.* at 69.

125. *See supra* note 105.

126. *See supra* note 114.

127. Most industrial cogeneration facilities are fairly large. Examples include: Caterpillar Tractor Co., 2.07 mw; Chevron USA, Inc., 2.5 mw, 7.5 mw, 10 mw, 4.3 mw; Hooker Chemicals and Plastic Corp., 42.4 mw; Hunt Wesson Foods, 1.0 mw. *Senate Amendments*, *supra* note 8, at 243-46.

Generally, the regulated sector has practiced utility cogeneration only on a large scale basis. San Diego Gas and Electric owns a subsidiary that produces 61 mw of power and 510,000 lb./hr. of steam. Gulf State Utilities has 100 mw of cogeneration capacity which produces 15-19 billion pounds of steam annually. That utility plans to add an additional 300 mw of capacity by the year 1990. *Id.* at 76-77 (statement of Edison Electric Institute).

128. Problems that large industries encountered in their approach to cogeneration are magnified in small companies.

G. *Rationale for the Belief that Full Electric Utility QCF Ownership will Result in More Cogeneration*

It is clear that electric utilities are better equipped to begin large scale cogeneration when compared with other industries. Many of the entry barriers felt by other businesses either do not factor into the electric utilities' investment equation at all, or are only minor factors. On the other hand, some of the barriers apply to all industries.

The utilities' strongest asset in entering QCF generation is their experience in power generation and marketing. All of the necessary technical and administrative frameworks are in place. QCF ownership requires little if any adaptation by utility management. An electric utility does not incur an opportunity cost when it invests in cogeneration. Unlike a non-utility, which must treat cogeneration as a supplemental investment, a utility is able to keep this within its primary business of power production.

Another advantage for a utility is the industry's satisfaction with lower rates of return on investment.[129] The lower QCF payback will not deter the traditional investor because these investors are accustomed to lower rates of return than are speculating investors.[130] Utilities will be more accessible to QCF investment capital than an unregulated industry because the latter must justify its low rates of return to its shareholders. Additionally, utilities have extensive regulatory compliance mechanisms in place that serve to lower compliance costs. As a result, electric utilities are in a position to comply more easily with the various federal and state statutes and regulations applicable to all forms of power production.[131]

Finally, utilities will be more likely to congenerate if the restraints of the joint venture requirement are removed. Utilities will not need to convince already unwilling industrialists of the benefits of cogeneration.[132] Instead, they can act on opportunities immediately because the opportunity needs to attract one party only.

Despite the advantages of full electric utility QCF ownership in creating more cogeneration, counter-arguments also are compelling.

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129. *Senate Amendments*, *supra* note 8, § 2.18; OTA, *supra* note 15, at 20.

130. Utility shares traditionally have been low yield investments with a high degree of stability. For that reason persons engaged in the investment field in earlier periods referred to them as stocks for "widows and orphans."

131. *See supra* notes 37-55 and accompanying text.

132. *See supra* notes 123-28 and accompanying text.

Potential utility abuse of the institutional arrangements created by QCF ownership can generate short- and long-term losses, resulting in higher regulated power costs.[133] To determine the desirability of full electric utility QCF ownership requires an analysis of its benefits and detriments. Such an analysis will reveal whether a change in ownership rules is warranted, and what limitations, if any, should be placed on utility QCF involvement.

IV. Possible Benefits from Full Electric Utility QCF Ownership

Arguments for full electric utility QCF involvement concentrate on the ability of the one hundred percent rule to: 1) Spur development of cogeneration capacity and technology in a manner that maximizes use of abundant fuels; and 2) mitigate the losses electric utilities will realize as a result of non-utility QCF development.

A. *Promotion of Cogeneration*

1. Increased Capacity

By the year 1990, industry will fail to tap an estimated twenty to sixty percent of potential congeneration capacity totalling 2,700 mw to 9,300 mw.[134] In the year 2000, industry will create the technical potential for two hundred thousand mw capacity.[135] If the twenty to sixty percent gap in capacity realization continues, between forty thousand and one hundred twenty thousand mw capacity will be lost. Although estimates of projected national electric capacity requirements vary, one respected projection foresees a demand for three hundred thousand mw additional capacity by the next century.[136] Lost cogeneration opportunities will necessitate substantial new amounts of central station power. At least a portion of that construction will be non-cogenerating oil- or gas-fired capacity. Even if such new capacity is highly fuel efficient there will be inherent inefficiencies and wasted heat.[137] Furthermore, oil- or gas-fired non-cogenerating capacity will not reduce America's dependence on foreign

133. *See infra* notes 181-96.

134. *Senate Amendments*, *supra* note 8, at 79 (statement of Edison Electric Institute).

135. OTA, *supra* note 15, at 10.

136. *Id.* at 52.

137. *See supra* note 1.

fuels.[138]

2. Benefits of Increased Competition

Generally, commentators agree that market competition is superior to governmental regulation for providing consumers with high quality, innovative products at the lowest possible cost.[139] Superior service and innovation are hallmarks of product markets with substantial competition and high consumer demand, such as computer manufacturing.[140] Such competition in the cogeneration field could yield comparable results in the areas of technologies and service to users.

3. Greater Supplies of Low-Cost Steam and Heat

Because cogeneration will create both electric and thermal energy for little more than the price of either created alone,[141] increased cogeneration will reduce the price of process heat by increasing supply and lowering fuel costs. This may encourage development in industries that utilize steam or heat. A rise in cogeneration as a result of increased utility activity will thus have this "spin-off" effect.

4. Increased Consumption of Coal

Coal fuel is abundant in the United States[142] and is an attractive alternative to petroleum derivatives or natural gas as an industrial fuel. Acceleration of coal use in energy production will help realize energy independence.[143] Historically, electric utilities have relied

138. The Energy Information Administration projects an increase of net imports of petroleum products of 5.3 million barrels a day over 1982 imports. ENERGY INFORMATION ADMINISTRATION, *supra* note 31, at xvi.

139. Some early and seminal criticisms of government regulation include Stigler & Friedland, *What Can Regulators Regulate? The Case of Electricity*, 5 J. OF L. & ECON. 1 (1962); Coase, *The Federal Communications Commission*, 2 J. OF L. & ECON. 1 (1959).

140. Competition also has its negative attributes. Recent history suggests the vulnerability of some industries. The mortality rate of computer entrepreneurs is high, bond values for firms such as AT&T have plummetted, and airlines such as Braniff have declared bankruptcy.

141. *See supra* note 18.

142. The Energy Information Administration projects one billion tons of annual coal production by 1990. ENERGY INFORMATION ADMINISTRATION, *supra* note 31, at 81. Coal exports by that year should top 143 million tons annually. *Id.* at 83.

143. Congress codified this attitude in the Powerplant and Industrial Fuel Use Act of 1978, Pub. L. No. 95-620, 92 Stat. 3289 (codified as amended in applicable

upon coal as a source of power.[144] Many utilities are highly sophisticated in the acquisition and combustion of coal. Some electric utilities own captive mines through subsidiaries of which the entire output is dedicated to satisfying the utility's requirements.[145] Other utilities have well-established channels through which they are assured a steady coal supply.

Widespread cogeneration spurred by electric utility involvement likely will result in the displacement of oil- and gas-fired installations by coal use. For example, a coal-fired electric utility QCF engaged in topping cogeneration might sell its exhaust heat or steam to a nearby business. The purchaser will be freed from creating the heat himself. If the purchaser had either engaged in or planned to engage in oil- or gas-fired thermal production, the national economy will realize a net reduction in oil or gas consumption. On a widespread basis these reductions can be substantial.[146]

5. Superior Integration of Low or High Marginal Cost Generation Capacity

Different types of generating capacity create varying marginal costs for produced power.[147] Electric utility generation structure is

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sections of chapter 42 U.S.C.). The statute explains that its purpose is "to encourage and foster the greater use of coal and other alternate fuels, in lieu of natural gas and petroleum, as a primary energy source." 42 U.S.C. § 8301(b)(3) (1982). *See generally* Toll & Cottingham, *Powerplant and Industrial Fuel Use Act of 1978 and Possible Amendments Thereto*, 11 ST. MARY'S L.J. 653 (1980).

144. Coal has far outstripped any other fuel as a heat source for electric utility power plants. In 1982 utilities generated 20.36 quadrillion BTU (quads) of heat. Of that figure, coal accounted for 8.79 quad, or approximately 40% of all heat production. ENERGY INFORMATION ADMINISTRATION, *supra* note 31, at 192. The Administration projects an increase to 16.6 quad, or approximately 51% of utility heat production. *Id.*

145. *See, e.g.*, Montana-Dakota Utils. Co. v. Billinger, 632 P.2d 1086 (Mont. 1981); Paper delivered by Samuel Huntington, Edison Electric Institute Legal Committee Meeting (October, 1981), *reprinted in* AMERICAN BAR ASSOCIATION, ANNUAL REPORT, SECTION ON PUBLIC UTILITY LAW 93 (1982).

146. For a forecast of energy trends, see generally ENERGY INFORMATION ADMINISTRATION, *supra* note 31.

Utilities more and more turn to coal to the exclusion of other energy forms. Recently, Cincinnati Gas & Electric decided to convert a 97% completed nuclear-fueled powerplant to coal because of high completion costs. Brooks, *Utilities' Plan to Switch Zimmer Plant from Nuclear to Coal Raises Questions*, Wall St. J., Jan. 23, 1984, at 3, col. 4.

147. Because avoided cost calculations are largely based on fuel costs and capac-

arranged so that base capacity (such as large central station generators) has a low marginal operating cost and peaking capacity (such as small diesel units) has a relatively high marginal cost.[148] Presently, utilities operate equipment with the lowest marginal cost whenever possible to realize maximum profit and to maintain the lowest possible rates, thereby stimulating demand.[149] The FERC rules have, to a certain extent, disturbed coordination of high and low cost generation capacity. The rules require utilities to purchase a QCF's entire output at full avoided cost regardless of the utility's needs.[150] If the avoided cost purchase rates that the utility must pay to the QCF are higher than the marginal cost of self-generated power,[151] ratepayers are forced to absorb the additional revenue paid to the QCF.[152] Furthermore, the redundancy in generating capacity will create a misallocation of society's resources.

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ity costs, changes in either will affect greatly avoided cost calculation. *See supra* note 68.

148. In this manner the utility uses the lowest cost generation capacity most effectively.

149. Demand in the summer is important because hot weather-spurred air conditioning causes a period of peak consumption for utilities. Air conditioning is, in many applications, a discretionary consumption of power. In most cases lack of air conditioning is not life-threatening. If power prices are too high, the discretionary user will turn his air conditioner off and the utility will lose revenue in a high revenue season. By keeping peak period prices low, the utility can realize greater income.

150. 18 C.F.R. § 292-303(a) (1984).

151. *See supra* note 68.

152. Standard PUC ratemaking formulas take into account expenses incurred by the utility in operations. The higher the expenses incurred, the higher the utility tariffs become. Avoided cost payments made by the utility to a QCF would enter into operating costs and raise tariffs. The following is a fairly sophisticated representation of the standard ratemaking formula:

$$RR = E + d + T + (V\text{-}D)R$$

RR = Required Revenue
E = Operating Expenses
d = annual depreciation expense
T = taxes
V = value of property serving public
D = accrued depreciation
R = return on investment
V-D = ratebase
(V-D)R = Profit

OTA, *supra* note 15, at 63.

B. *Increased Utility Financial Stability*

At least as pressing as the need to advance cogeneration is the need to stabilize the financially troubled utility industry.[153] A number of factors in recent years have led to what some analysts consider a crisis point.[154] Operating costs of oil- and gas-fired capacity have risen with fuel costs.[155] Staggering cost overruns in nuclear facility construction have led to the specter of default for several utilities.[156] State PUCs have failed to grant rate of return increases commensu-

153. Investment analysts express their confidence in a business' financial health through bond ratings. In 1970, 60% of all utility bond issuers had a Standard and Poors rating of AA minus or higher (AAA is highest). By 1981, that percentage had fallen to 29%. *Utility Financing: Hearings on the Financial Condition of Utilities and their Future in the 1980s Before the Subcomm. on Energy Conservation and Power of the House Comm. on Energy and Commerce*, 97th Cong., 1st Sess. 13 (1981) [hereinafter cited as *Utility Financing*] (statement of Matthew Holden, Jr., Commissioner, Federal Energy Regulatory Commission, quoting testimony of Ann Faber, Standard and Poor's).

154. *See The Future of the Nation's Energy Utilities: Implications for Federal R.D.&D.: Hearings Before the Subcomm. on Energy Development and Applications of the House Comm. on Science and Technology*, 97th Cong., 1st Sess. 20 (1981) [hereinafter cited as *R.D.&D.*]. *See also* Gentry *supra* note 49, at 299-302. *See generally Utility Financing*, *supra* note 153. *Cf. A Dark Future for Utilities*, BUS. WEEK, May 28, 1978, at 46.

155. Rising fuel costs have caused utilities to shift to coal and nuclear capacity, with concomitant long lead times and publicly perceived adverse side effects. *See* ENERGY INFORMATION ADMINISTRATION, *supra* note 31, at xv.

156. *See Pulling the Nuclear Plug*, TIME, Feb. 13, 1984, at 34. In 1983 the Washington Public Power Supply System (WPPSS) defaulted on $2.25 billion in bonds for two abandoned power plants (WPPSS-4 and WPPSS-5). *WPPSS Defaults*, 112 PUB. UTIL. FORT., Aug. 18, 1983, at 53. The Bonneville Power Administration now seeks to guarantee or pay off loans in order to procure loans from wary lenders for the purpose of completing WPPSS-3, a nearly finished nuclear plant. St. Louis Post-Dispatch, May 14, 1984, at 2C, col. 3.

Meanwhile cost overruns continue to force nuclear plant cancellations. Marble Hill was scrapped by the Public Service Company of Indiana. St. Louis Post-Dispatch, Jan. 17, 1984, at 2A, col. 1. New England Power Company canceled its Pilgrim II and was then denied cost recovery. Wall St. J., June 13, 1984, at 8, col. 1.

Analysts warn investors of the risks involved in utility investments when nuclear problems are apparent. *See, e.g.*, Quinn, *Utility Stocks in the Spotlight*, NEWSWEEK, June 18, 1984, at 80. Poor bond ratings have forced some electric utilities to seek high-interest bank loans. Simions & McCoy, *Nuclear Utilities' Money Raising is Disrupted by Industry Problems*, Wall St. J., Feb. 14, at 35, col. 4; Bailey, *Utilities with Troubled Nuclear Units Turn to Banks as Bond Ratings Fall*, Wall St. J., Jan. 20, 1984, at 3, col. 2. Some of these same utilities are now on the brink of bankruptcy. *See* Wald, *Utilities' Chapter 11 Prospects*, Wall St. J., June 26, 1984, at 1.

rate with these developments.[157] In addition, fluctuations in consumer demand for power have made it difficult for many utilities to earn more than seventy-five percent of their allowed rate of return.[158]

As a result of these financial problems, 1981 utility stock traded at about one-half of its 1965 market value,[159] and in 1980 traded at less than seventy-three percent of book value.[160] Between 1970 and 1980, electric utility common shares averaged an eleven percent return on investment, while shares of competing investments rose from a ten percent rate of return in 1970 to a fifteen percent return in 1980.[161] Obviously, a change is in order.

There is, of course, no simple solution to the problems facing America's power industry. Congress is taking a closer look at the problem,[162] although action may not be forthcoming until there is an actual crisis. One possible solution that commentators and the electric utility industry are advancing is power production decentralization through utility ownership of QCFs and small power production facilities.[163] Decentralization would benefit utility financial status in two ways: 1) by providing an additional source of revenue; and 2) by offsetting losses utilities will realize when major industrial power consumers begin to cogenerate and cease to be utility customers.

1. Cogeneration as an Additional Source of Revenue

Recently, utilities have argued in favor of diversification.[164] Many are engaged in energy related fields such as coal mining,[165] while

157. Studness, *Genesis of the Current Financial Plight of Electric Utilities*, 105 PUB. UTIL. FORT., June 19, 1980, at 54.

158. *R.D.&D.*, *supra* note 154, at 3 (statement of Charles Benore, Vice President, Paine, Webber, Mitchell & Hutchins).

159. *Id.* at 2.

160. *Utility Financing*, *supra* note 153, at 1 (opening statement of Hon. Richard L. Ottinger).

161. *R.D.&D.*, *supra* note 154, at 2 (statement of Charles Benore, Vice President, Paine, Webber, Mitchell & Hutchins).

162. The hearings cited above are the extent of the involvement, as Congress has enacted no new legislation on the issue. If utilities' financial status continues to decline, legislative action may be the only viable solution.

163. *See* Gentry, *supra* note 49, at 307-11; *R.D.&D.*, *supra* note 154, at 88 (statement of Edison Electric Institute); *Senate Amendments*, *supra* note 8, at 181 (statement of Peter W. Brown, Director, Energy Law Institute).

164. *See generally* York & Malko, *Utility Diversification: A Regulatory Perspective*, 111 PUB. UTIL. FORT., Jan. 6, 1983, at 15.

165. *See supra* text accompanying note 145.

others have entered wholly unrelated fields.[166] These holdings provide the utilities revenues independent of regulated operations. These revenues will mitigate hardships suffered by a decline in power demand.

QCF ownership can be a profitable subsidiary investment for an electric utility. Irrespective of the demand for power or losses stemming from regulated capacity, QCFs will remain profitable as long as operating costs remain below avoided costs. Because the parent company is obligated by the FERC regulations to purchase the QCF's entire power output, electricity demand will not factor into revenues.

2. Mitigate Losses from Industrial Cogeneration

Every kilowatt of new industrial capacity creates a double loss for electric utilities. First, the utility has lost a source of revenue. Rather than purchasing from the utility, the cogenerator produces its own power. The resulting decrease in the utility's income necessitates a shifting of the former customer's contributions to the utility's costs, and a ratebase return to other customers.[167] Second, the cogenerator is not a utility supplier, with the utility guaranteeing purchase of cogenerator output. At times when instantaneous avoided cost[168] is lower than designated avoided costs, the utility will lose money.

Full utility QCF ownership would mitigate some of these losses by providing additional revenues.[169] Each kilowatt of utility QCF power would offset a kilowatt of industrial QCF power. The utility would realize a loss only to the extent of the fixed cost of the QCF.[170]

V. Possible Detrimental Effects of Full Electric Utility Ownership of QCFs

Arguments against full electric utility ownership of QCFs are founded in the potential conflicts that arise when unregulated and

166. In 1984, for example, a subsidiary of Laclede Gas Company, St. Louis, Missouri, began a direct solicitation of utility customers for the purpose of selling life insurance.

167. *See generally* 1 A. Priest, *supra* note 5, at 327-45.

168. Instantaneous avoided cost is the marginal cost a utility realizes at the moment it adds an additional kilowatt of power to the grid.

169. The utility ratepayer would receive a benefit only if a governing public utilities commission requires the utility to take nonregulated income into account in calculating revenue requirements, thus permitting the benefit to "flow through."

170. The utility would recover that fixed cost over time.

regulated firms compete in the same market when the unregulated participant must deal directly with the regulated participant.[171] One can place these potential conflicts into three categories: a) unfair competition; b) self-dealing; and c) regulated utility rate and planning distortion. These problems may lead to the monopolization of the QCF industry by electric utilities coupled with the simultaneous gouging of utility ratepayers.

A. *Unfair Competition*

PURPA section 210 emphasizes that the QCF-electric utility relationship must be just, fair, reasonable, and nondiscriminatory.[172] Congress stressed that language to eliminate discrimination as a barrier to nonregulated cogeneration and small power production.[173]

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171. For a collection of materials addressing the problem as experienced in the telecommunications industry, see T. MORGAN, *supra* note 119, at 778-826.

The desire of utilities to enter the field of solar energy is particularly well documented. *See generally* Lawrence and Minan, *The Competitive Aspects of Utility Participation in Solar Development*, 54 IND. L.J. 229 (1979); Lawrence & Minan, *Solar Energy and Public Utility Rate Regulation*, 26 UCLA L. REV. 550 (1979); Sparrow, *Public Utility Involvement with Distributed Solar Systems*, 1 SOLAR L. REP. 955 (1980). Their participation in the distribution of solar devices, either by sale or lease, is seen by regulators as presumptively invalid. The Residential Energy Conservation Utility Program under the National Energy Conservation Planning Act, 42 U.S.C. §§ 8201-8278 (1982), regulates the conduct of persons engaged in financing and constructing conservation systems for residential structures of four or fewer units. *See id.* The Act also regulates utility companies engaging in sales, service, installation, and/or financing of such conservation devices. *Id.* The utilities have an affirmative statutory duty to prevent unfair trade practices that ultimately may result in decreased residential participation in solar and other energy conservation methods. *Id.* One commentator suggests a common law duty as well. *See generally* Note, *The Duty of a Public Utility to Render Adequate Service*, 62 COLUM. L. REV. 312 (1962).

Financing of solar installations by utilities is also a major issue. Seven states (Iowa, Wisconsin, North Carolina, New York, Ohio, California, and Oregon) have enacted either statutes or administrative regulations requiring utilities to provide such financing. *See* Colton, *Mandatory Utility Financing of Conservation and Solar Measures*, 3 SOLAR L. REP. 767, 768 (1982). A primary question is whether it is the utility stockholder or ratepayer who must shoulder the expenses of such financing. Pennsylvania's Public Utilities Commission ruled that the stockholder must pay. Pennsylvania PUC v. Equitable Gas Co., 21 P.U.R. 4th 34 (Pa. P.U.C. 1977). One commentator foresees a beneficial trend, and envisions the utility of the future as a provider of full energy services rather than of simply a particular type of fuel. *See* Colton, *supra*, at 768.

172. *See supra* notes 64-67 and accompanying text.

173. *See* H. CONF. REP. 95-1750, *reprinted in* 1978 U.S. CODE CONG. & AD. NEWS 7797, 7832.

New law, however, can change long standing attitudes only with time.

The structure of QCF industry provides ample opportunity for utilities to discriminate in favor of facilities in which they hold an interest.[174] The greater the interest, the greater the incentive for discrimination. First, a utility may seek unlawfully to refuse interconnection with a QCF by alleging falsely that the facility is an unsafe burden on the utility grid. The QCF will have to resort to legal processes[175] in order to contest that allegation, regardless of its merits. The QCF will realize a financial loss resulting from lost generating revenues as well as expensive legal fees. The possibility of such expenses serves as a chilling effect on the QCF market entrant.

Perhaps the greatest potential threat from the one hundred percent rule is the market power that utilities hold. Because they enjoy an officially sanctioned monopoly in an area of continuous consumer need,[176] the utilities have great economic power notwithstanding their current financial difficulties. Coupling that power with utility technical expertise results in the potential for monopoly leverage in the QCF marketplace. For example, utilities can construct and operate QCFs at a financial loss for considerable periods of time by using the regulated portion of their business to provide operating funds.[177]

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174. *See generally* N. DEAN, *supra* note 17, at 154-96.

175. Judicial review enforcement of § 210 is provided for in 16 U.S.C. § 824a-3(g) (1982). Any person may bring an action against a state public utility commission, a utility, or a QCF to enforce any provision of § 210. *Id.* Congress granted the FERC the power to enforce § 210 in § 824a-3(h). If the Commission does not bring an enforcement action within 60 days, the aggrieved party may do so himself. *Id.* § 824a-3(h)(B).

176. See *supra* note 40 for a definition of natural monopolies. *See generally* 2 E. KINTNER, 2 FEDERAL ANTITRUST LAWS § 12.14 (1980); Posner, *Natural Monopoly and Its Regulation*, 21 STAN. L. REV. 548 (1969); Turner, *The Scope of Antitrust and Other Economic Regulatory Policies*, 82 HARV. L. REV. 1207 (1969).

Demand elasticity refers to how variations in price affect demand for a market commodity. The more a given price change effects market demand, the greater is the elasticity of demand. Thus, if a 5¢ change in the price of a widget costing 50¢ alters demand up or down by 40%, then the widget market is highly sensitive to price; it is highly price elastic. If the price of gadget may rise or fall substantially with no significant corresponding demand change, then price is inelastic. Generally, commodities with no market substitutes are relatively price inelastic, particularly if the commodity is a necessity of life. *See generally* T. MORGAN, *supra* note 119, at 5-23.

177. This transaction borders on the fraudulent, and the utility would be at risk of liability and prosecution. In the "fishbowl" of public utility ratemaking, such an action by a utility is unlikely.

Only the utilities' largest QCF competitors will be able to compete. Of these competitors, many would abandon self-generation rather than maintain continued losses in a subsidiary investment.[178]

Such utility activities will most likely violate antitrust laws.[179] Antitrust suits, however, are expensive to litigate and difficult to win.[180]

178. Standard Oil Company used this technique with great effectiveness in the late nineteenth century. Standard Oil Co. v. United States, 221 U.S. 1, 43 (1911). *See also* Utah Pie Co. v. Continental Baking Co., 386 U.S. 685 (1967) (use of market strength in California to monopolize market in Utah).

Since PURPA requires utilities to purchase a QCF's output, and specifies purchase rates, much of a utility's market power would not affect competitors. Larger QCFs may choose to contract individually with the utility, and rely on their larger size and greater reliability to realize a higher market price than PUC-determined market cost. It is this contract-power market where utility market leverage may harm cogeneration.

179. Section 2 of the Sherman Act prohibits "monopolization." 15 U.S.C. § 2 (1982).

One violation uses predatory pricing, *supra* note 178, as a tool in the use of monopoly strength in one market to gain monopoly strength in another. The United States Supreme Court addressed specifically the issue of market leverage in United States v. Griffith, 334 U.S. 100 (1948). In that case, the Court found that a motion picture theatre owner could not use his monopoly of theatres in one town to gain a competitive advantage in towns in which he had no monopoly. *Id.* at 101-10. The defendant had lumped together towns in which he had a monopoly and towns in which he did not when booking firms with distributors. To gain favor in the monopoly towns, the distributor granted special advantages in the non-monopoly towns to the owner. In the Court's opinion, "If monopoly power can be used to beget monopoly, [§ 2 of the Sherman] Act becomes a feeble instrument indeed." *Id.* at 108.

In Berkey Photo, Inc. v. Eastman Kodak Co., 603 F.2d 263 (2d Cir. 1979), *cert. denied*, 444 U.S. 1093 (1980), a number of photographic products companies sued Kodak for § 2 violations, claiming that Kodak sought to exercise its monopoly power in photographic film to gain a monopoly in the camera manufacturing industry. The court reversed a judgment against Kodak, holding that simply introducing a new film in a format adaptable only to its new camera was not exercising monopoly leverage, because the plaintiff itself could manufacture a camera which could receive the new film. In dictum, however, the court noted: "The use of monopoly power attained in one market to gain a competitive advantage in another is a violation of § 2, even if there has not been an attempt to monopolize the second market. It is the use of economic power that creates the liability." *Id.* at 276. As applied to utilities and QCFs, *Griffith* and *Berkey Photo* will prohibit utilities from exercising their monopoly power in their regulated sector to better compete in the unregulated sector.

Privately-owned publicly regulated utilities are within the jurisdiction of the federal antitrust laws notwithstanding their governmental associations. City of Lafayette v. Louisiana Power & Light Co., 435 U.S. 389, 394-408 (1978).

180. *See* Posner, *A Statistical Study of Antitrust Enforcement*, 13 J. OF L. AND ECON. 365 (1970). Posner's study shows that in the years between 1945 and 1964, antitrust cases brought by the Department of Justice lasted an average of 35 months. Litigated cases averaged 50 months, and cases heard by the Supreme Court averaged

Consequently, the Department of Justice will not bring a public enforcement action in every instance of an alleged violation.

B. *Self-Dealing*

Any time that a parent company and subsidiary engage in mutual transactions a danger exists that the parent company will extract excessively high profits from the subsidiary.[181] The problem is particularly serious when the parent is a regulated monopoly utility and the high profits are paid for by captive ratepayers. It arises frequently in the context of telephone utility transactions with its mother company. When American Telephone and Telegraph (AT&T) owned large portions of local telephone operating companies,[182] dealings between those companies and AT&T often precipitated litigation by disgrun-

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65 months. *See id.* at 377. While no firm data exists on the duration of private antitrust actions, enough information exists to determine that plaintiffs rarely prevail on the merits. Of 221 private antitrust suits reaching final disposition in 1969, only eight resulted in a judgment for the plaintiff. In 1966, of approximately 1150 cases, only 17 found the plaintiff victorious. *Id.* at 383. Assuming that the complainant's counsel is operating on a contingency fee, that attorney may face four years of work with a slim chance of success. Counsel may seek to avoid all but the most clear-cut Sherman Act violations. The chilling effect is obvious if the client must pay expenses.

181. Dealings between a parent company and a subsidiary are subject to the antitrust laws. *See, e.g.*, United States v. Yellow Cab Co., 332 U.S. 218 (1947). A taxicab manufacturer bought several large cab companies and established purchase contracts between manufacturing and operating subsidiaries. The Court stated:

> The test of illegality under the Act is the presence or absence of an unreasonable restraint on interstate commerce. Such a restraint may result as readily from a conspiracy among those who are affiliated or integrated under common ownership as from a conspiracy among those who are otherwise independent. . . .The corporate interrelationships of the conspirators, in other words, are not determinative of the applicability of the Sherman Act. That statute is aimed at substance rather than form.

Id. at 227.

See also Timken Roller Bearing Co. v. United States, 341 U.S. 593 (1951) (American corporation and foreign subsidiary engaged in conspiracy to divide world bearing market). *See generally* L. SULLIVAN, HANDBOOK OF THE LAW OF ANTITRUST 325-29 (1977).

Self-dealing problems sometimes arise when a subsidiary company is owned in part by a parent corporation, and in part by a minority shareholder. If the parent does not conduct transactions with the subsidiary fairly, shareholders may bring derivative suits for damages to the corporation. *See, e.g.*, Sinclair Oil Corp. v. Levien, 280 A.2d 717 (Del. 1971) (if parent corporation disregards binding contract with subsidiary, subsidiary has a cause of action for breach of contract).

182. In 1982, the Department of Justice and American Telephone & Telegraph reached a consent decree by which AT&T would divest itself of local operating company ownership. In the telephone industry, at least, the traditional self-dealing prob-

tled ratepayers and utility commissions.[183] Similar problems arise when electric utilities own coal mines that supply the requirements of the parent company.[184]

Identical problems emerge when an electric utility is the sole shareholder in a QCF. If the parent and subsidiary have a contractual buy-sell arrangement,[185] it is reasonable to imagine that the bargaining positions taken by the parties were diametrically opposed to each other. Furthermore, it may be difficult to prove padded rates because each QCF-utility agreement is unique.[186]

Utility-QCF self-dealing also presents the potential for "cream-skimming." Because a utility will be able to put a new QCF into either the regulated portion of its business or the unregulated portion, the most costly units will go into the rate base, and the less costly (and therefore more profitable) units will go to the subsidiary. A utility choosing to install bottoming cycle cogenerators[187] operating off industrial exhaust heat can choose the method more advantageous to it, rather than to the public. Ratepayers will see this choice reflected in their electric bills.[188]

C. *Rate and Investment Distortions*

Extensive electric utility involvement in QCF ownership can affect

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lem is now largely moot. *See* United States v. Western Elec. Co., Inc., and Am. Tel. & Tel., 1982-2 Trade Cases ¶ 64,900 (Aug. 24, 1983).

183. *See generally* Note, *Treatment of Affiliated Transactions in Rate Making: Western Electric Company and the Bell System*, 56 B.U.L. REV. 558 (1976). There are two basic approaches in dealing with transactions between affiliates, one of which is a regulated utility. The first approach adopts a "market price" standard by which the profit realized by the supplying company is judged by other companies providing similar products. This is the traditional approach taken by public utility commissions. California has taken an alternative approach, adopted by several other states, which assumes that the supplying company is a branch of the locally regulated utility. The rate of return realized by the supplier may not be greater than that of the utility. *See* 1 A. PRIEST, *supra* note 5, at 103.

184. *See supra* notes 143-46 and accompanying text.

185. FERC Rule 292.304(d) permits qualifying facilities to have the option of selling power to a utility "as available" or pursuant to a legally enforceable contract. 18 C.F.R. § 292.304(d) (1984). The contract sales price may be based either on the avoided cost at the time the parties entered the contract or the avoided cost at the time of the actual sale. *Id.* §§ 294.304(d)(2)(i), (ii).

186. The problem is exacerbated with greater numbers of QCFs.

187. *See supra* note 22 and accompanying text.

188. *See supra* note 152.

utility rates in both the short- and long-term. These distortions result from the avoided cost basis of determining QCF purchase rates and from the ability of the utilities to divert funds from regulated service into non-regulated endeavors.

The avoided cost calculation of rates paid to QCFs for supplied power requires that an electric utility pay the QCF the full cost of that power, as if the utility had obtained it elsewhere,[189] either by self-generation or by "wheeling."[190] If the electric utility has its own generating capacity,[191] it may be in a position to control avoided cost by seeking the most expensive form of peak generation[192] and permissible fuels when planning for new capacity, either in earnest or for the purpose of avoided cost calculation.[193] When the higher priced capacity enters the ratebase the electric utility will be able to engage in a form of dipping. Revenues will increase: 1) As a result of higher regulated income from the inflated ratebase;[194] 2) from the higher costs to the regulated utility as a result of higher avoided cost payments;[195] and 3) from the increased profitability of the QCF at the expense of the regulated parent company. Once again, the ratepayers will pay this difference.

Another distortion concerns the diversion of resources from the regulated sector to the unregulated sector. Rather than putting money into the ratebase and improving base facilities, electric utilities may put their monetary resources into more profitable endeavors.

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189. *See supra* note 68.

190. "Wheeling" is the transmission of power generated in one location to a distributor situated in another location.

191. Many utility companies own only the primary and secondary lines necessary to provide power delivery. All power these firms sell must be obtained elsewhere.

192. Peak generation refers to those times when demand is at its highest. Because these periods are intermittent (usually occurring on hot summer days when many persons operate air conditioning equipment) it is more profitable to build small generators and run them at only these times than it is to build new baseload capacity to handle new high peaks.

193. Although the Powerplant and Industrial Fuel Use Act of 1978, *supra* note 143, prohibits construction of new generating capacity using natural gas or petroleum as a primary energy source, 42 U.S.C. § 8311(1) (1982), exemptions are available on the basis of need. *See id.* § 8322. Utilities would have strong incentives to fight tenaciously for one of these exemptions.

194. FERC rule 292.302 requires large utilities to file cost data with the state utility commission for the purpose of calculating avoided costs. Qualifying facilities that submit a request must be provided with comparable data.

195. *See supra* note 152.

The power produced by unregulated bottoming cogenerators would be priced higher than power produced by conventional means. This is so because the avoided cost rate would be high and because of the higher cost of the equipment. The utility can realize greater capacity for the same capital input if all long-term investments went into the regulated sector of the business.

In summary, full QCF ownership by utilities will discourage industrial and commercial participation in alternate energy production despite benefits under section 210 of PURPA. Congressional intent is to encourage utilization of waste heat from industrial processes generally, not from particular electric utility generation.[196] Even though utility cogeneration will offset some industrial combustion by providing process steam through steam lines,[197] oversaturation of the QCF market by the utilities will not advance the recovery of waste heat. The industrialist will continue to buy power from the utility and society's ultimate energy savings will suffer. PURPA section 210 will have the effect of invigorating the electric utility industry.

VI. Suggestions for Change

Neither the benefits nor the liabilities of full electric utility QCF ownership suggest the superiority of one form over the other. Although it appears that the current ownership rules have a deterring effect on realization of cogeneration capacity, the regulatory framework is still new[198] and rash action may only upset the foundations for potential future growth in other industries.

It is not certain that electric utilities will engage in unlawful and unethical practices under a one hundred percent rule, but there have been problems in the past with similarly regulated industries.[199] If the FERC takes certain precautionary steps, however, the benefits of a one hundred percent rule can be realized without the detriments.

The best way to measure the effectiveness of the one hundred percent rule would be for state PUCs to limit total permitted utility QCF capacity and to limit the size of a given QCF installation. This would be done pursuant to FERC rules. The ownership requirements should begin with the assumption that non-utility QCF ownership is

196. *See supra* notes 1-6 and accompanying text.

197. *See supra* note 20 and accompanying text.

198. The final rules in many states are only three years old.

199. *See supra* notes 134-38 and accompanying text.

the ideal, but that utilities should enter where they are able to promote cogeneration. PUCs should assess each utility service area in order to determine the potential and actual QCF development. An ideal level of QCF penetration will find industry realizing a substantial percentage of capacity at all levels of organizational size. If realized penetration is unsatisfactory, the PUC should permit the utility to undertake a controlled entry into the market.

Initially, the utility should create an arm's length subsidiary with separate offices, management, and accounting procedures. The subsidiary should then be permitted to construct several nominally-sized QCFs. The unit would operate as a normal QCF, but the subsidiary would be under an affirmative obligation to cooperate with potential cogenerators as to all aspects of plant operations. The utility QCF would serve as a pilot program in order to familiarize the business community in the utility's service areas with cogeneration operations.

When non-utility cogeneration begins to proliferate, PUCs should permit additional utility QCF construction moderated by a percentage of the total QCF capacity on line. For example, a thirty to fifty percent ceiling on total utility owner QCF capacity would eliminate the potential for utility dominance in the field.

VII. CONCLUSION

The FERC rules promulgated under section 201 of PURPA limit participation by electric utilities in QCF ownership to fifty percent of equity, even though these rules may be contrary to congressional intent. Their purpose is to limit the potential for electric utility antitrust violations, self-dealing, and rate and planning distortion. It is not certain that these evils will not occur with less than full utility QCF ownership. The benefits of cogeneration would be realized more quickly if the federal government permitted limited full utility participation. Utility success will encourage other types of industry to engage in cogeneration more quickly than they might otherwise have done. Finally, the troubled electric utility industry needs an influx of new capital in order to regain stability. Entry into the nonregulated electric power generation market could spark investor interest and get the utilities back on their feet. Congress should amend section 201 of PURPA to allow electric utilities to own one hundred percent of QCF equity in an appropriate regulatory environment.

COMMENTS