Alternative Energy Power Production: The Impact of the Public Utility Regulatory Policy Act

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I. INTRODUCTION[1]

Rising electric rates and the uncertain availability of fossil fuels since the early 1970's have caused a reconsideration of the preferred way to produce and distribute energy. Finding ways to exploit alternative energy sources, and to get the most out of the oil and gas we do use, have become necessary components of the nation's energy strategy. Cogeneration and renewable resource technology are two means to these ends.

The term "cogeneration" refers to the production of two different forms of useful energy from a single source. Cogeneration systems are of two basic types: "top-cycling" and "bottom-cycling." In "top-cycling" systems, the most common variety, excess energy (normally steam) from an electricity generation process is used for a second purpose, such as space heating or industrial processing. "Bottom-cycling" systems utilize waste heat (or heat created by burning waste products) from an industrial process to generate electricity. This recycling of energy is estimated to result in generation systems that are sixty to eighty percent efficient, as compared with the thirty-three percent efficiency experienced from most centralized electric plants.[2]

Renewable resource technologies involve the use of biomass, water, wind power, solar energy and geothermal energy to produce electricity. The environmental and regulatory issues arising out of the application of some of these technologies are discussed in other articles in this issue.[3] Here it is enough to recognize that these alternative energy technologies, like cogeneration technolo-

1. The following list of acronyms and abbreviations may be helpful to the reader:

FERC:	Federal Energy Regulatory Commission
QF:	Qualifying Facility
PUHCA:	Public Utilities Holding Companies Act
NEA:	National Energy Act
ETA:	Energy Tax Act
NECPA:	National Energy Conservation Policy Act
FUA:	Powerplant and Industrial Fuel Use Act
NGPA:	Natural Gas Policy Act
DOE:	Department of Energy
CFR:	Code of Federal Regulations

2. Wooster, *Cogeneration: Revival Through Legislation?*, 87 DICK. L. REV. 705 (1983). Note that "supplemental firing," which is the introduction of additional energy into the second stage of the cycle, is permitted in both types of cogeneration process. 18 C.F.R. 292.202(d)-(e) (1985).

3. *See* the following articles included in this issue: Stoloff, Mallory, & Stearns, *Legal Issues Raised by the Environmental Impacts of Photovolteic Energy and Wind Energy Conservation Sys-*

gies, are often employed outside the context of utility monopolies, in small power production facilities.

In 1978, Congress recognized the potential of these developments and enacted a package of laws designed to encourage them. The National Energy Act was composed of five acts: the Public Utilities Regulatory Policy Act (PURPA);[4] the Energy Tax Act of 1978 (ETA);[5] the National Energy Conservation Policy Act (NECPA);[6] the Powerplant and Industrial Fuel Use Act of 1978 (FUA);[7] and the Natural Gas Policy Act of 1978 (NGPA).[8]

Only the Energy Tax Act lacked provisions to encourage cogeneration. The FUA and the NGPA were designed to forestall further institutional barriers to cogeneration. The FUA prohibited electric utilities and major industrial fuel burners from burning oil or natural gas as the primary fuel in any new installations and authorized conversion of existing oil and natural gas burning plants to other fuels where feasible.[9] Similarly, the NGPA authorized the Federal Energy Regulatory Commission (FERC) to exempt some cogenerators from the incremental pricing provisions.[10] The NECPA, by amending the Energy Policy and Conservation Act of 1974, provided some limited grants for cogeneration projects.[11]

These Acts commonly included an extensive array of provisions designed to increase the understanding and use of renewable resource energy production.[12] It was in PURPA, however, that Congress most directly addressed itself to the need to enlist utility

tems, 11 COLUM. J. ENVTL. L. 379 (1986); Sampson & Charo, *Access to Sunlight: Resolving Legal Issues to Encourage the Use of Solar Energy*, 11 COLUM. J. ENVTL. L. 417 (1986).

4. Pub. L. No. 95-617, 92 Stat. 3117 (1978) (PURPA).

5. Pub. L. No. 95-618, 92 Stat. 3174 (1978) (ETA).

6. Pub. L. No. 96-619, 92 Stat. 3026 (1978) (NECPA).

7. Pub. L. No. 95-620, 92 Stat. 3289 (1978) (FUA).

8. Pub. L. No. 95-621, 92 Stat. 3350 (NGPA). For an overview of how these five Acts work to encourage cogeneration, *see* Siler, *Cogeneration and Small Power Production*, in ALTERNATIVE ENERGY 7-1 to 7-34 (Buck & Goodwin eds. 1984).

9. 42 U.S.C. § 8302(10) (1978). Note, however, that the Secretary of Energy has the power to issue cogenerators a permanent exemption from these restrictions. 42 U.S.C. §§ 8322(c), 8352(c) (1978).

10. These exemptions are set forth at 45 Fed. Reg. 38,080 (1980).

11. Pub. L. No. 95-621, § 206(c)(3), 92 Stat. 3380 (1978).

12. *E.g.*, Pub. L. No. 95-618, § 101, 92 Stat. 3174 (1980) (residential energy credits); Pub. L. No. 95-619, §§ 241-248, 92 Stat. 3228, 3228-3235 (1978) (extensive financing provisions to ease investment in solar energy systems); Pub. L. 95-619, §§ 521-569, 92 Stat. 3275, 3275-3285 (1978) (provisions committing the federal government to study and use solar energy technologies).

companies into the new movement to encourage decentralized energy production. To this end, the statute established a general scheme to foster cooperation between utilities and cogenerators.

Since this legislative movement in 1978, both the political and economic climates have changed. There is still, however, a strong sentiment that conservation, national security and efficiency interests would be best served by the expansion of cogeneration and alternative source energy production.[13] Utilities will have a continuing role in the future of these developments and PURPA, as a result, will continue to be a crucial piece of legislation to understand and to improve upon. After an overview of the historical context in which PURPA was passed, this article outlines the principle requirements of PURPA as they have been elaborated by federal regulations. In Section IV, it considers key issues raised in the implementation of PURPA. Such an examination hopefully sheds some light on the progress in, and the remaining disincentives to, increasing decentralized energy production.

II. THE NEED FOR FEDERAL ACTION TO PROMOTE UTILITY COOPERATION

Utility monopolies are a relatively recent historical development. In 1900 self-generated power accounted for sixty percent of all U.S. capacity.[14] By 1973, however, 4.2 percent of U.S. capacity was accounted for by self-generated electricity; less than three percent of U.S. capacity was cogenerated.[15] The demise of decentralized, small-scale energy production as a competitive force in the U.S. began with the advent of the turbogenerator in 1903, and the huge economies of scale made possible by it. Capital investment in large-scale plants that could serve large numbers of customers from central locations was necessary to take advantage of these economies. Utility companies, exercising their privileged position, were able to offer preferential rates to indus-

13. NATIONAL AUDUBON SOCIETY, THE AUDUBON ENERGY PLAN 93-94 (1984).

14. Munson, *The Growing Role of Independent Electricity Producers*, PUB. UTIL. FORT., May 30, 1985, at 12.

15. *Id.* at 12 (regarding self-generated capacity figure); Lock, *Encouraging Decentralized Generation of Electricity: Implementation of the New Statutory Scheme*, 2 SOLAR L. REP. 705, at 711 (1980) (regarding cogeneration figure).

trial customers as well as sub-metering contracts[16] to gain an ever-increasing share of the market.[17]

Until the 1970's, utilities were able to continue their expansion. Accepting public regulation in exchange for freedom from competition, they were able to pass on the benefits of their declining marginal costs to their ratepayers. Between 1945 and 1970, real prices for electricity declined by 70%.[18] During this period, to protect what were perceived to be the advantages of this "natural monopoly" in energy production, state regulatory authorities reinforced the protections afforded to the monopoly status of the utilities.[19] Public Utility Commissions felt bound to protect the solvency of the utilities upon whom customers were already relying; competitive energy production was seen as unnecessary duplication at best.[20] Thus, both local and federal action was taken to ensure continued utility monopoly.[21] As a consequence, the use of cogeneration declined steadily and the development of renewable resource technologies stagnated.

16. Sub-metering is the practice of a utility offering to let a private generator buy power at wholesale rates and to resell it to tenants or customers at retail rates as an inducement to the private generator to cease production.

17. Wooster, *supra* note 2, at 707-09. At the time, utilities often offered low rates to industrial users, who were the chief source of cogenerated power. The rates were often below "embedded costs," *i.e.*, below the average cost of the power, figuring in fuel, operations, maintenance and capital costs for plant, transmission and distribution.

18. *Are Utilities Obsolete?*, BUS. WK., May 21, 1984, at 117, col. 1.

19. *See* Stearns, *Energy Savings in Residential Buildings: The Role of Investor-Owned Utilities*, 11 COLUM. J. ENVTL. L. 261 (1986).

20. Wooster, *supra* note 2, at 712-714. Backed by the courts, state commissions were particularly active in protecting the utilities from competition by industrial generators. For example, disputes over the utilities' duty to provide back-up service and to accept retail customers were decided in favor of the utilities. "Certificates of public convenience and necessity," which power producers were required to obtain before building new facilities, were denied to non-utilities.

In the 1960's, "total energy systems" briefly became popular, in which isolated units (usually gas-fired) provided all heating, cooling and lighting to a large apartment complex or shopping center. However, the necessary metering was held to be a "sale" making the system subject to utility regulatory schemes.

21. *Id.* at 715. Many municipalities granted an exclusive franchise to a utility, a power still permitted to half our local governments as of the 1970's. *See* Oklahoma Gas & Electric Co. v. Total Energy, Inc., 499 P.2d 917 (Okla. 1972) (developer who proposed to install a total energy plant needed to obtain a franchise by submitting a referendum to the voters of the entire municipal area.) Antitrust suits during the 1930's required paper companies to give up their hydroelectric and waste-wood operations. Other paper companies gave up their power subsidiaries when faced with the possibility that they would be covered by the Public Utilities Holding Company Act (PUHCA), and its attendant regulations.

With the energy crisis of the early 1970's, the era of inexpensive electricity and secure fossil fuel resources ended. Due to rising oil prices, climbing capital equipment costs, diminishing economies of scale and increasing environmental regulations, utility electrical rates began to rise sharply.[22] These factors coupled with increased private and public conservation efforts resulted in a sharp decline in the growth rate of demand. By the late 1970's, that rate had fallen to just over 4%, and by the early 1980's to less than 2%.[23]

These developments caused a rash of problems for the utilities, and set the stage for a major restructuring of national policy attitudes toward energy production.[24] A few utilities responded by moving away from building new, large power plants and toward small power production facilities.[25] Generally, however, the development of utility-owned cogeneration and alternative resource facilities has been slow.[26] Moreover, utilities have used their monopoly status to oppose competition from private, decentralized producers.[27]

The primary reason for this opposition by the utilities is the fear that dealing with small producers will result in a loss of profits.[28] First, the allowed rate of return of a utility is based upon its capital investment. Externally-produced power reduces the need for capital investment in new base load capacity and can thereby negatively effect the rate of return a utility will be allowed. Externally-produced power also removes a customer while creating a supplier. Since the fixed costs of centrally produced electricity are consequently spread among fewer retail purchasers, the result is a lower short term profit and eventually higher electricity costs to non-producing customers. Furthermore, outside facilities,

22. Gentry, *Public Utility Participation in Decentralized Power Production*, 5 HARV. ENVTL. L. REV. 297, 300; *Are Utilities Obsolete?*, *supra* note 18, at 117, col. 2.

23. *Are Utilities Obsolete?*, *supra* note 18, at 117, col. 3.

24. *See generally Why Cheaper Electricity May Be On the Way to Consumers*, BUS. WK., Oct. 29, 1984, at 76 [hereinafter cited as *Cheaper Electricity*]; *Are Utilities Obsolete?*, *supra* note 18; Gentry, *supra* note 22.

25. Gentry, *supra* note 22, at 311; *Cheaper Electricity*, *supra* note 24, at 76.

26. Gentry, *supra* note 22, at 314-15. See also Stearns, *supra* note 19.

27. Munson, *supra* note 14, at 15. "Examples [of this] include refusal to interconnect, refusal to allow back-feed of electricity into the utility grid, overly complex regulations governing parallel operations, refusal to 'wheel' power across their lines, excessively high prices for back-up power, and excessively low prices for power purchased from private producers." Gentry, *supra* note 22, at 316.

28. Gentry, *supra* note 22, at 316.

while creating no tax credit for the utilities, create unpredictable demand for back-up power. The possibility of high back-up demand during peak hours can increase a utility's need for peak capacity and thereby raise production costs.[29] Utilities also cite lack of control over production and planning[30] and safety concerns[31] as reasons for their opposition.

This utility reluctance, coupled with a growing national concern to avoid dependence on foreign fuel sources and to encourage the conservation of non-renewable resources, set the stage in 1978 for legislation which would open a window of opportunity for electricity entrepreneurs.

III. PURPA and FERC Regulation: The Framework of Relationships Between Utilities and Qualifying Facilities

The principal aim of PURPA[32] was to remove the major obstacles to cogeneration and small scale renewable resource production which grew out of the combination of an unfavorable legal climate and the unaccommodating attitude of the utilities.[33] Three of these obstacles were particularly significant: 1) the unwillingness of utilities to purchase the electric output of cogenerators and small power producers, 2) the likelihood that utilities would charge discriminatorily high rates for the back-up power required by these producers, and 3) the risk that cogenerators and small producers which provide electricity to a utility's grid would be subjected to regulation as an electric utility.[34]

To minimize these obstacles, PURPA contemplates a partnership between the state and federal authorities that regulate utilities. The statute expressly regulates federally-owned utilities and the interstate activities of federally-regulated utilities.[35] The actual content of this regulation is, however, in a large part delegated to the Federal Energy Regulatory Commission (FERC) which is required under the statute to promulgate a range of rules

29. Hagler, *Utility Purchases of Decentralized Power: The PURPA Scheme*, 5 Stan. Envtl. L. Ann. 154, 157-58 (1983).

30. Gentry, *supra* note 22, at 317.

31. *Id.* at 316; Hagler, *supra* note 29, at 158.

32. Pub. L. No. 95-617, § 210, 92 Stat. 3144 (1978), codified at 16 U.S.C. § 824 (1982).

33. *See supra* text accompanying notes 14-31.

34. 45 Fed. Reg. 12,214, 12,215 (1980), codified at 18 C.F.R. §§ 292.302-.602 (1985).

35. 16 U.S.C. § 824(a) (1982).

relating to qualifying facilities (QFs).[36] The statute then mandates implementation of FERC-promulgated rules by state utility regulatory agencies.[37]

The broad scope of PURPA was challenged shortly after its enactment, but the supreme Court affirmed PURPA provisions on two occasions. In *FERC v. Mississippi*,[38] the state of Mississippi and the Mississippi Public Service Commission sought a declaratory judgment that certain provisions of PURPA, including section 210, went beyond the scope of congressional power under the Commerce Clause, and violated state sovereignty under the Tenth Amendment by exempting QFs from state regulation and requiring states to implement federal rules. The District Court found PURPA unconstitutional under both theories. The Supreme Court, however, reversed both holdings on appeal.

Discussing the Commerce Clause issues, the Court noted that no state relies solely on its own resources for power, and that the Mississippi utilities bought and sold electricity across state lines.[39] Congress therefore acted rationally in determining that PURPA was essential to protect interstate commerce.

With regard to the Tenth Amendment challenge, the Court treated the Act's exemption of QFs from state regulation as a simple case of federal preemption. While it considered the implementation requirements to be "more troublesome," it found that since the states could enforce the rules by simply hearing disputes between the parties, PURPA merely required the states to enforce federal law.[40]

The second challenge to go to the Supreme Court was brought by three utilities in the *American Electric Power*[41] case. The original suit challenged three FERC rules and the FERC decision not to

36. 16 U.S.C. § 824a-3(a) (1982).

37. *See generally* 16 U.S.C. § 824(a) (1982).

38. 456 U.S. 742, 752 (1982).

39. *Id.* at 757.

40. *Id.* at 759-61. In the only dissent on § 210, Justice Powell said that he would strike down its procedural requirements as violative of state sovereignty. *Id.* at 771. *But see* Garcia v. San Antonio Metropolitan Transit Authority, 105 S. Ct. 1005 (1985), overruling National League of Cities v. Usery, 426 U.S. 833 (1976). The recent *Garcia* decision seems to significantly expand federal authority to require state action to implement federal law, further weakening the doctrinal basis for Justice Powell's dissent.

41. American Electric Power Service Corp. v. FERC, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd sub nom.* American Paper Instit. v. American Electric Power Service Corp., 461 U.S. 402 (1983).

set fuel use qualifying criteria for cogenerators.[42] The Court of Appeals upheld the FERC on only two of the issues, but the Supreme Court reversed the appellate court as to the other two issues, thereby legitimating the FERC's exercise of its authority.[43]

The rules promulgated by the FERC pursuant to PURPA therefore form a valid framework within which subsequent state action to encourage cogeneration and small power production will take place. The FERC rules elaborating the most central PURPA requirements are outlined below.

A. *Qualifying Status*

The statute leaves the definition of a qualifying facility largely to the FERC, except that such facility must not be owned "primarily" by an electric utility.[44] In order to become a qualifying facility under FERC rules, a cogeneration or small power production plant must meet additional requirements as to size of facility, energy source and efficiency. Qualifying procedures are also detailed.[45]

The total capacity of all small power production facilities using the same resource, owned by the same person, and located at the same site may not, for example, be greater than 80 megawatts (Mw).[46] In addition, a small power production facility's primary energy source must be biomass, waste, renewable resources, geothermal resources, or any combination thereof, and its use of oil, natural gas and coal may not, in the aggregate, exceed 25% of the total energy input of the facility during any calendar year period.[47]

Cogenerating plants face different qualifying criteria depending on whether they are top-cycling facilities or bottom-cycling facili-

42. The three rules challenged were 1) the full avoided cost rule, 18 C.F.R. § 292.304(a); 2) the simultaneous buy-sell rule, *id.* at § 292.304(b)(4); and the automatic interconnection rule, *id.* at § 292.303(c)(1) (1985).

43. The Court of Appeals had upheld the buy-sell rule and the lack of fuel use criteria.

44. 16 U.S.C. § 824a- 3(j) (1982); 18 C.F.R. §§ 292.204 (qualifying criteria for small power production facilities), 292.205 (qualifying criteria for cogeneration facilities), 292.206(a) (ownership criteria) (1985). See also discussion *infra* text accompanying notes 217-230.

45. 18 C.F.R. § 292.207 (1985).

46. 18 C.F.R. § 292.204(a)(1) (1985).

47. *Id.* at § 292.204(b)(1).

ties.[48] Each must, however, produce a minimum useful energy or power output.[49]

B. *Rate Regulation*

To remedy discriminatory treatment of small power producers by utilities, PURPA mandates the setting of rules to require utilities to sell electric energy to qualifying facilities and purchase electric energy from such facilities at just and nondiscriminatory rates.[50] FERC has, therefore, promulgated general regulations guiding how purchase and sale rates should be calculated. These rules are most notable for the proliferation of rates which they allow.[51]

In order to provide the greatest possible encouragement to QF development, FERC set the utility purchase rate at the maximum allowed under PURPA: the utility's full avoided cost.[52] The difficulties that have attended the implementation of this provision are addressed in Section IV. It is worth noting here, however, that the purchase rate provisions are subject to other provisions which attempt to guarantee the flexible application of the avoided cost rule. First, states may set a purchase rate of lower than full avoided cost where the authorized state rate-makers determine such a lower rate is just, reasonable to electric consumers, in the public interest, nondiscriminatory and sufficient to encourage QF development.[53] Alternatively, a state regulatory authority may

48. 18 C.F.R. § 292.205(a), (b) (1985). For definition of these terms, see *supra* text accompanying note 2.

49. *Id.* at § 292.205(a)(1) (the useful thermal energy output of top-cycling facilities must, during any calendar year, be no less than 5 percent of the total energy output). This last requirement avoids the possibility that single purpose facilities, including plants using renewable resources but not meeting the size requirements for small power producers, may be granted qualifying status by generating a token amount of steam heat. 45 Fed. Reg. 17,966-67 (1980)); § 292.205(a)(2) (1985) (the useful power output for a bottom-cycling facility must, during any calendar year, be no less than 45% of the energy input of natural gas or oil).

50. 16 U.S.C. § 824a-3(a)-(d) (1982).

51. See discussion of avoided cost rates, *infra* notes 93-157 and accompanying text.

52. 18 C.F.R. § 292.304(a)(2) (1985). Avoided cost is defined as the incremental costs of the electric utility of electric energy or capacity or both, which, but for the purchase from a QF, such utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6) (1985); *see also infra* text accompanying notes 93-137. To aid in the task of computing avoided costs, the utilities are required to furnish their cost data. 18 CFR § 292.302(b) (1985).

53. 18 C.F.R. §§ 292.304(a)(1), (k)(3) (1985).

seek a waiver from the application of the FERC rate regulations.[54] Finally, the rules permit a variation of full avoided cost rates where a utility and a QF contract for a different rate.[55]

Where full avoided cost rates apply, determination of full avoided costs is to be made according to the following factors:[56]

— availability of power from the qualifying facility during daily or seasonal peak load periods;

— reliability of the cogeneration facility;

— presence of a firm contract to supply the power;

— ability of the facility to coordinate outages with the utility;

— willingness of the facility to accept interruption of power; and

— adaptability of the facility to system emergencies.

For QFs with a capacity of 100 kilowatts (Kw) or less, the rules also call for standard, nondiscriminatory purchase rates to be established for each utility. Such standard rates are discretionary for larger QFs.[57]

Rates for the sale of power to QFs are also required to be nondiscriminatory, just, reasonable and in the public interest.[58] In particular, the regulation specify four types of electricity supply services which the utilities must make available to the QFs at nondiscriminatory rates:[59] supplementary power,[60] back-up power,[61] maintenance power,[62] and interruptible power.[63] The rates for these services must not be based upon the unsupported assumption that reductions in electric output by all QFs with which a utility deals will occur simultaneously, or at peak hours, and must

54. *Id.* at § 292.403. *See infra* text accompanying notes 67-74.

55. *Id.* at § 292.301(b).

56. *Id.* at § 292.304(e); *see infra* text accompanying notes 93-137.

57. *Id.* at § 292.304(c).

58. *Id.* at § 292.305(a).

59. *Id.* at § 292.305(b), rule made pursuant to PURPA requirements in 16 U.S.C. § 824a-3(a) (1982).

60. "Supplementary power" means power that the QF uses regularly in addition to its self-generated energy. 18 CFR § 292.101(8) (1985).

61. "Back-up power" means power to replace self-generated power during an unscheduled outage. *Id.* at § 292.101(9).

62. "Maintenance power" means power supplied during scheduled outages of the QF. *Id.* at § 292.101(11).

63. "Interruptible power" means power which the utility may cut off under specified conditions. *Id.* at § 292.101(10).

reflect a QF's ability to coordinate its outages with those of the utility.[64]

C. *Interconnection Costs*

While a utility is required to interconnect with QFs, interconnection costs must be borne by the QFs.[65] The rules further provide that if a QF agrees, a utility that might otherwise be under an obligation to purchase energy may transmit that energy to another electric utility. The utility to which the energy is transmitted must purchase that energy as if it were being supplied directly to it and may not include transmission charges in its purchase rate.[66]

D. *Exemptions & Waivers*

Certain classes of QFs are exempted from specified Federal Power Act provisions, the Public Utility Holding Company Act (PUHCA), and from state laws respecting utilities' rates, finances, and organization.[67] Under a limited number of circumstances, exceptions can also be made to the general obligation on electric utilities to purchase the electricity produced by QFs and to sell to QFs on a nondiscriminatory bases.

64. *Id.* at § 292.305(c). This provision rejects the utilities' argument that their high back-up rates are justified by the necessity of maintaining capacity sufficient to supply all customers with power without relying on the QFs. It does, however, allow ratemakers to consider, for example, whether the QF is supplying power on a "firm" contract under which the QF is obligated to deliver power in fixed amounts for a specified period; or on a "non-firm" delivery bases, under which the QF supplies power only as it sees fit. Either supply basis is authorized by regulation, 18 C.F.R. § 292.304(d) (1985).

65. 18 C.F.R. § 292.306 (1985). Interconnection costs can vary widely, ranging from $12 to $1,300 per kilowatt, depending upon "generator type, the system size, the amount of equipment already in place, and a particular utility's or state's requirements for equipment type or quality." B. FINNEGAN, Cogeneration—An Overview 5 (submitted to the EEI Environmental Dialogues group) (May 29, 1984). Proper interconnection is needed to assure the safety of line personnel working on transmission and distribution lines. Note that interconnection with larger systems may also require sophisticated (*i.e.*, expensive) metering systems providing data on kilowatt hours used, time of use and power factor corrections. *Id.* at 6. The criteria for ordering interconnection are similar to those for ordering wheeling: that the order be in the public interest, increase economic efficiency or electric supply reliability, and not unreasonably burden the utility subject to the order. *See* 16 U.S.C. §§ 824j-824k (1982). For a discussion of wheeling, *see infra* text accompanying notes 184-210.

66. 18 C.F.R. § 292.303(d) (1985).

67. 18 C.F.R. §§ 292.601-.602 (1985). Rules passed pursuant to authority defined in 16 U.S.C. § 824a-3(e)(1)-(3) (1982).

Purchase is not required, for example, when an electric utility is experiencing a system emergency,[68] or during periods in which the purchases will result in net increased operating costs to a utility.[69] Similarly, a utility's obligation to sell power may be waived where the state regulatory authority finds that compliance with such a requirement would impair the utility's ability to render adequate service to its customers or place an undue burden on the utility.[70] An exception to the interconnection obligation is available if, because of purchases and sales to be made through the interconnection, the utility would become subject to regulation as a public utility under the Federal Power Act.[71]

In general, however, utilities cannot easily escape the obligation to purchase QF power and sell power to QFs.[72] Waivers will be permitted for individual utilities on a showing by the applicant that designated standards have been met, but waivers *en masse* are unlikely to be authorized.[73] No utility has yet met the requirements for a waiver of the sale obligation, and the successful waiver of the purchase obligation is more the exception than the rule.[74]

IV. Issues Related by State Implementation of PURPA

PURPA and the FERC regulations passed pursuant to it were attempts to "evolve concepts in a newly developing area."[75] Consequently, a great deal of discretion was left to state authorities regarding how they should perform their obligations, resulting in the fact that states may follow the guidelines of FERC regulations and yet vary widely in how they: 1) set the rates for purchase of electricity from QFs;[76] 2) set the rates for sales of electricity to QFs;[77] 3) establish the data filing requirements that permit potential QFs to determine the avoided costs likely to be paid by the

68. 18 C.F.R. § 292.307(b) (1985).

69. *Id.* at § 292.304(f).

70. *Id.* at § 292.305(b)(2).

71. *Id.* at § 292.303(c)(2).

72. Anglin, *Purchase and Sale Obligations to Qualifying Facilities: The Law and Exceptions*, Pub. Util. Fort., Oct. 3, 1985, at 52.

73. *Id.* at 53, citing holding of Re Oglethorpe Power Corp. FERC Dkt. No. ER 81-56-000 (July 23, 1985).

74. *Id.* at 53, 54.

75. 45 Fed. Reg. 12,226 (1980).

76. 18 C.F.R. § 292.304(c) (1985). Standard purchase rates are required for QFs with a design capacity of 100 kilowatts or less.

77. *Id.* at § 292.305(a).

utility;[78] 4) establish the rates for, and means of providing, supplementary, back-up, maintenance and interruptible powers to QFs;[79] and 5) set the conditions for interconnection, including the operational standards required.[80]

In approaching the task of implementation, some states generally empowered utility regulators to take the necessary action to implement PURPA, while others passed statutes and regulations which gave more detailed guidelines to the regulators regarding how the spirit of PURPA was to be implemented.[81] Frequently, state statutes extended PURPA-type requirements to municipal utilities and cooperatives which would otherwise have fallen outside PURPA requirements.[82]

The degree to which state implementation of PURPA has stimulated decentralized energy production by promoting QFs is not easy to determine. Neither is it easy to decipher how one state's approach to PURPA may have been more effective than another. One reason for the difficulty in determining PURPA's effects is the uncertainty caused by court challenges.[83] These court challenges delayed the implementation of the federal regulations by many states. While state regulatory authorities and nonregulated electric utilities were directed to implement the regulations within one year after they went into effect,[84] only sixteen states met this deadline.[85] Even by March 1983, six states and the District of Columbia were still without final rules of implementation.[86] Although all states were in compliance by January 1986,[87] the impact of the delay on QF development must be recognized. In ad-

78. *Id.* at § 292.302.

79. *Id.* at § 292.305(b), (c).

80. *Id.* at §§ 292.306, 292.308.

81. Hamilton, *Standard Contracts and Prices for Small Power Producers*, 11 WM. MITCHELL L. REV. 421, 448 (1985). *See, e.g.*, CONN. GEN. STAT. ANN. § 16-243a (West Supp. 1985); IND. CODE ANN. § 8-1-2.4-4 (Burns 1982); MINN. STAT. ANN. § 216B.164 (Supp. 1985).

82. *See, e.g.*, CONN. GEN. STAT. ANN. 16-243b (West Supp. 1985) which defines private power producer to include a state or political subdivision of a state that produces power through cogeneration or renewable resource production.

83. See *supra* text accompanying notes 38-43.

84. 18 C.F.R. § 292.401 (1985).

85. Wooster, *supra* note 2, at 734. For a survey of state plan implementation, *see* NAT'L. ASSOC. OF REGULATORY UTILITY COMMISSIONERS, STATE COMMISSION PROGRESS UNDER THE PUBLIC UTILITIES REGULATORY POLICY ACT OF 1978 (December 1980).

86. Wooster, *supra* note 2, at 735.

87. The FERC does not formally monitor the evolving status of PURPA implementation in every state but considers all states in compliance because they have all taken action of some sort. A sole exception is Nebraska, which was exempt from the implementation

dition, the investment decisions of would-be QFs most likely were also affected by the unpredictability of fuel costs in general, the regional availability of low cost fuel and the lack of available expertise and information concerning the technological and business risks involved in these emerging technologies.

One indicator of PURPA's effect on QFs is the number of facilities which have filed for qualified status under PURPA. These findings suggest a significant interest in PURPA incentives on the part of electricity entrepeneurs. In the first three years of reports, 119 filings were made from facilities that promised, in total, approximately 3,500 Mw of new capacity—the equivalent of three to four new base load plants.[88] The potential number of cogeneration projects, based on Department of Energy statistics, increased

requirement because the state does not regulate electrical utilities. Telephone interview with the FERC Public Inquiries Office (February 3, 1986).

88. FERC Filings for Qualification as New Facilities (1983)

State	Number of Filings	Rated Capacity (Kw)
Alabama	1	37,400
Arizona	1	375
California	55	1,009,975
Connecticut	1	150
Florida	13	383,120
Georgia	2	76,600
Hawaii	1	19,400
Idaho	1	5,000
Kansas	1	33,730
Louisiana	1	100,000
Maine	1	46,700
Massachusetts	3	583,400
Michigan	1	22,400
Mississippi	4	7,177
Missouri	1	80,000
Nebraska	Not Available	Not Available
New Hampshire	1	1,800
New Jersey	2	35,300
New York	1	100
North Carolina	2	58,000
North Dakota	1	9,000
Ohio	1	16,500
Oregon	2	100,000
Pennsylvania	2	55,500
Tennessee	7	27,228
Texas	4	750,000
Virginia	6	55,507
Washington	2	29,000
Wyoming	1	5,000
TOTALS	119	3,548,362

more than sixteen percent in 1984, to more than 3,600 potential plants in 1985.[89] By the end of 1984, cogeneration alone was contributing about seven percent of the nation's electric power production capacity.[90]

However, most of the growth in the number of cogeneration facilities has taken place in a handful of states. Between 1980 and 1983, nearly half the filings came from California, and two thirds from California, Florida, Tennesse and Virginia combined. With respect to rated capacity, Texas and Massachusetts combined with California to produce two thirds of the total capacity offered by these new producers.[91] The Californian experience, where independents supplied only 100 Mw of the state's electricity in January 1982, but were capable of supplying 1,659 Mw of power by 1985, is a development of particular importance.[92]

The experience of these particularly successful states, as well as the experience of states where PURPA implementation has apparently been less effective, has led to the identification of several important issues, including: 1) how best to set avoided cost purchase rates; 2) how to improve the bargaining power of QFs; 3) how to increase utility cooperation in the promotion of qualified facility production; and 4) how to manage the conflict between increased cogeneration and improved air quality control. Future legislative action at both state and federal levels should be taken in light of an understanding of these issues. The following sections discuss each of these in turn.

A. *How Best to Set Avoided Cost Purchase Rates*

A key element of a QF's ability to predict future revenues lies in its ability to rely on a minimum required purchase cost for its power. If the standard rates set by the states are too low, or are

Wooster, *supra* note 2, at 758, updated with data from the FERC Quarterly Report on Qualifying Small Power Production and Cogeneration Facility Filings 1 (July 1, 1984) (on file in the office of the *Columbia Journal of Environmental Law*). Table III of this report, which summarize the age, type and size of small power production and cogeneration filings for FY 1980-FY 1984, is reproduced as an Appendix to this Article. In January 1985, the FERC changed its reporting of facility filings from quarterly to annual reports. Hence, as of January 1, 1986, the July 1984 statistics are the most recent.

89. Morris & Grutsch, *The Upcoming Boom in Cogeneration*, PUB. UTIL. FORT., May 30, 1985, at 18.

90. *Id. See also* NATIONAL AUDUBON SOCIETY, *supra* note 13, at Vol. 2, Table F-2, p. F3, (indicating cogeneration contributed 3% of power-production capacity in 1980).

91. Wooster, *supra* note 2, at 759.

92. Munson, *supra* note 14, at 15.

available only to the smallest QFs, small-scale producers may be at a great disadvantage.[93] PURPA rules state that a purchase rate will satisfy the requirement of being just, reasonable and nondiscriminatory if the rate equals the "avoided cost," defined as the incremental costs to that electric utility of electric energy or capacity or both, which, but for the purchase from the qualifying facility or facilities, such utility would generate itself or purchase from another source.[94] Assuming that the full avoided cost, if accurately measured, provides a sufficiently high standard to encourage QF investment, one way to aid QFs is to ensure that state's standard rates reflect avoided costs as accurately as possible. The present wide variation among standard rates and methods of determining them suggests that inaccuracies occur.

FERC rules identify the factors to be considered in setting such an avoided cost rate.[95] However, these factors are very generally stated. In practice, FERC has indicated that it would approve any method of calculation which reasonably accounts for a utility's avoided cost and provides the required encouragement for QFs.[96] Where states adopted only FERC rules, the methodology applied may be determined largely by individual utilities.[97] Other states have, to a greater or lesser degree, adopted specific methodologies which utilities must employ in making their calculations.[98] The result of this structure has been a proliferation of methodologies of calculating avoided costs which contributes to widely disparate purchase rates.

In 1983, Vermont, for example, offered a standard on-peak energy credit[99] of 9 cents per kilowatt-hour (Kwh), compared to In-

93. There is evidence to suggest that these factors do in fact affect QF development. In her analysis of FERC's data on filings for qualifying status, Wooster found that the states in which the most interest had been generated had relatively high standard rates and offered them to QFs with capacities above 100 Kw. Woster, *supra* note 2, at 759.

94. 18 C.F.R. §§ 292.101(b)(6) (definition of avoided cost), 292.304(b) (1985) (relationship of purchase rate to avoided cost).

95. 18 C.F.R. § 292.304(e) (1985). For the FERC's discussion of the effects of these variables on avoided costs, *see* 45 Fed. Reg. 12,225-27 (1980) (to be codified at 18 C.F.R. § 292.304(c), (e)). See *infra* text accompanying note 56.

96. 45 Fed. Reg. 12,226 (1980).

97. *See, e.g.*, 4 Mo. ADMIN. CODE § 240-20.060 (1982); WASH. ADMIN. CODE R. 480-105 (1983).

98. Hamilton, *supra* note 81, at 448; Wooster, *supra* note 2, at 737, n.203 lists twenty-two states requiring detailed procedures.

99. "Energy credit" is the energy cost component of an avoided cost calculation, *i.e.*, the cost which a utility would incur on a day-to-day basis in order to produce the energy being purchased from a QF. Such costs vary in relation to changes in demand. As demand

diana's 1.36 center per Kwh.[100] Similarly, Utah Power paid capacity credits[101] of 2.6, 3.5, 4.79 cents/Kwh depending on whether the rate was set by the commission of Wyoming, Utah or Idaho respectively.[102] Although much of this disparity can be attributed to variations in fuel cost, the different approaches to avoided cost calculation also contributed. Whether there is a preferred means to calculating avoided cost is, therefore, a subject of continuing and extensive debate.[103]

The evaluation of available calculations is the task of an economist, not a lawyer. The goal here is merely to alert the reader to the basic components of an avoided cost calculation, to identify some of the most common approaches currently being used to quantify those components, and to raise some of the problems that have been identified as difficulties in application of the formulae in use. The purpose of this overview is to urge upon policymakers the need for a more coherent policy regarding avoided cost calculations, one which, if it cannot defend a uniform methodology can, at least, provide clearer guidelines as to the application of these major approaches.[104]

Avoided cost calculations require determination of three major components: 1) the energy component of the utility's costs; 2) the capacity component of the utility's costs; and 3) the component reflecting the utility's environmental and societal costs.

The energy component or "energy credit" is a reflection of the costs which a utility would incur on a day-to-day basis in order to produce the energy being purchased from a QF.[105] The capacity

exceed utility capacity, for example, due to time of day, season of the year or demographic shifts, the average cost of production increases because utilities must bring older, less efficient plants on-line. Wooster, *supra* note 2, at 721, 735-45 (discussing various methodologies used by states to calculate the energy credit given to cogenerators).

100. *Id.* at 744-45.

101. "Capacity credit" is the capacity cost component of an avoided cost calculation, *i.e.*, the fixed capital investment cost of generation and transmission facilities that a utility would expend if it were to produce the electricity being purchased from a QF. FERC regulations require purchase rates to contain a capacity credit only if a utility needs new capacity. *Id.* at 721, 745-50 (discussing various state methodologies used to calculate the capacity credit). *See also* 18 C.F.R. § 292.304-(e) (1985).

102. Wooster, *supra* note 2, at 750.

103. *See, e.g.*, Howe, *Cogeneration Rates: The Present and Future of Full Avoided Costs*, PUB. UTIL. FORT., May 10, 1984, at 55; Yokell & Marcus, *Rate-Making for Sales of Power to Electric Utilities*, PUB. UTIL. FORT. Aug. 2, 1984, at 21-28.

104. For a detailed discussion of the application of these approaches as of 1983, see Wooster, *supra* note 2, at 734-62.

105. *See supra* note 99.

component or "capacity credit" reflects the fixed capital cost of generation and transmission facilities that would be incurred by a utility to produce the electricity being purchased from a QF.[106] Finally, environmental and social costs are those costs attributable to the reduced need to consume fossil fuel and to those costs saved as a consequence of the smaller capacity increments and shorter lead times available with additions of capacity from qualifying facilities.[107]

1. Energy Credits

It has been said that "the energy component is the simplest to determine."[108] Nevertheless, in a detailed examination of formulae used in 1983 to determine the energy credits, Wooster outlined at least three major approaches to the calculation, each of which appeared in almost as many variations as the number of times it was adopted.[109]

The "incremental heat rate" approach, in the most general terms, bases the energy credit on the cost of fuel required to produce the energy from a certain incremental block of a utility's system load.[110] The "production use" approach involves a more sophisticated use of models, such as System Lambda,[111] which account for variable operation and maintenance costs as well as the fuel costs in producing energy from a certain incremental block of the system load.[112] The third approach, the "proxy" system, can only be applied to utilities that are part of a group of utilities (a power pool) which may buy and sell electricity among themselves. Under this system, the energy component of power purchased from the power pool is adopted as a proxy for the measure of avoided energy cost.[113]

The outcome of applying any one of these methodologies depends on the variables chosen for input into the equation. On

106. *See supra* note 101.

107. 18 C.F.R. §§ 292.304(e)(3) and (e)(2)(vii) (1985). Note that the environmental cost of fossil fuels and the costs to society of the loss of responsiveness to changing demand inherent in the long construction times for fossil fuel plants are largely not internalized by utilities, but must in any case be considered in an avoided cost calculation. Hamilton, *supra* note 81, at 449-50.

108. Hamilton, *supra* note 81, at 450.

109. Wooster, *supra* note 2, at 731-43.

110. *Id.* at 737-38.

111. *Id.* at 738, n.211.

112. *Id.* at 738.

113. *Id.* at 740-43.

these variables there appears neither consensus nor evaluative guidelines. For example, should the production models used in the production cost approach be required to isolate the costs of the *last* incremental block of energy produced or the projected *next* incremental block? What *size* incremental block of system load should be costed under the incremental heat rate approach or the production cost approach,[114] or should costing be done *per* generating *unit*? In applying the incremental heat rate approach should the *projected* cost of fuels or their *historical average* be used?[115] Under the proxy unit approach, how should one determine which unit is the avoidable one?[116]

In addition, there appear to be few resolutions to the persistent accusations of distortion that attend each of the models. The proxy system, for example, is said not to accurately reflect the costs of utilities that join a power pool for the advantages of central dispatch rather than in lieu of building additional capacity.[117] Likewise, the production models are accused of being difficult to verify and thus susceptible to biased input by the utilities.[118]

2. Capacity Credits

Capacity credits have variously been set by reference to the cost of an appropriate generating unit, the cost of capacity bought from a pool, the utility's carrying charge for prospective capacity, or the differential between the capital cost of optimum capacity expansion without QFs and the capital cost of that expansion with QF input.[119] Each approach is problematic and controversial.[120] By definition the calculations must be made on estimations and a forecast of future capacity requirements.[121] The undertaking is to discern whether the power being offered by a QF would permit

114. Though FERC regulations give some guidance as to the size of the incremental block to be used, substantial discretion is still left to the states. The block shall be "not more than 100 megawatts for systems with peak demand of 1,000 megawatts or more, and in blocks equivalent to not more than 100 percent of the system peak demand for systems of less than 1,000 megawatts." 18 C.F.R. § 292.304(e) (1985). This system takes into account the varying costs of non-peak and peak time production, because it is at peak time that expensive, older and inefficient plants will come on line.

115. Wooster, *supra* note 2, at 739.

116. Yokell & Marcus, *supra* note 103, at 27.

117. Wooster, *supra* note 2, at 740.

118. Yokell & Marcus, *supra* note 103, at 23.

119. Wooster, *supra* note 2, at 745-50; Yokell & Marcus, *supra* note 103, at 24-26.

120. Hamilton, *supra* note 81, at 451.

121. 45 Fed. Reg. 12,226 (1980).

the utility to defer or cancel future generating capacity or would allow a utility to change the mix of its generating capacity so that, for example, smaller, less expensive peaking plants could be built rather than more expensive base load plants.[122]

A key issue which needs to be resolved is what generating capacity should constitute the basis of the saved cost calculation. Utilities generally argue that existing plants should be used to calculate avoided costs, not more expensive future plants.[123] Qualified facilities, on the other hand, benefit under the argument that the costs of future facilities avoided as a consequence of purchases from QFs more accurately represent avoided costs.[124]

Recognizing that avoided capacity cost predictions also require sophisticated anticipation of future energy demand and capacity, the federal rules include the reliability of a QF's power supply as one consideration to be entered into the equation determining capacity credits.[125] In order for QFs to have capacity credits calculated into the purchase rate, states have required, among other things, that the QF: enter into a firm contract with the utility; meet reliability standards; meet minimum capacity requirements; exhibit particular energy factors; or adhere to peak hour supply requirements.[126] These conditions are arguably not so onerous as to defeat the general policy of PURPA: to encourage the development of cogeneration and small power production.

One approach that does seem to defeat this purpose is to require that each individual qualifying facility produce a consistent level of power at or near its capacity for a substantial portion of the year.[127] Particularly for QFs with smaller than 100 Kw capacity, or for facilities with large seasonal variations in capacity like solar or wind installations, this prerequisite can deprive them of ever claiming capacity credits.[128] It has been suggested that this discrete unit approach ignores the FERC regulation directing utilities to consider the "individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's sys-

122. Hamilton, *supra* note 81, at 451.

123. Howe, *supra* note 103, at 55.

124. *Id. See also Cogeneration and Small Power Production: State of PURPA 210 Implementation*, 3 SOLAR L. REP. 659 (1981).

125. 18 C.F.R. § 292.304(e)(2)(ii) (1985).

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

127. Hamilton, *supra* note 81, at 454 n.196. Capacity factors of 70-80% have been required of individual facilities before they can earn capacity credit.

128. Yokell & Marcus, *supra* note 103, at 25.

tem."[129] On this basis, calculations should consider the cumulative stability of supply that can be afforded by the range of QFs supplying a utility.

It has even been suggested that a state-wide approach to the measurement of avoided capacity would be defensible based on the policy of encouraging the development of these alternative resources.[130] As of 1984, however, only three states had accepted this aggregation principle and require utilities to make aggregate capacity payments to all small power producers.[131]

The influence that excess capacity should have on the calculation of capacity credits is also a source of debate. Two-tier, short-term and long-term rate structures are one means of setting rates with a sensitivity to the fact that excess capacity might not endure over the life of a contract between a utility and a QF.[132] One variation on this solution was adopted in California. California utilizes two definitions of avoided cost: short and long-run marginal cost (SRMC and LRMC).[133] Each includes both an energy and a capacity component. The major distinction between them is the basis for computation: while SRMC reflects an energy credit plus the effects of the QF's power generation on the utility's reserve margins and reliability, LRMC derives from the capital and operating costs of facilities that remain unbuilt because of the power supplied by the QF.[134]

Another means is to levelize, or average, the two-tier rates into capacity payments spread over the term of the contract between a QF and a utility rather than capacity payments paid only during that period of the contract during which the utility is actually saving on capacity construction.[135] Arguably the additional financial support that this would provide to QFs could prove an incentive to small producers to build up their capacity during periods of utility excess so that it was on line when excess was exhausted.[136]

129. *Id.* citing 18 C.F.R. § 292.304(e)(2)(vi) (1985).

130. Hamilton, *supra* note 81, at 456.

131. *Id.* at 455 n.203, citing F. SISSINE, WIND ENERGY DEVELOPMENT AND UTILITY CAPACITY CREDITS: A REVIEW OF RESEARCH, IMPLEMENTATION AND POLICY ISSUES UNDER THE PUBLIC UTILITY REGULATORY POLICY ACT (PURPA) 18 (Cong. Research Service Rep. No. 84-101, SPR, June 1984).

132. Howe, *supra* note 103, at 56.

133. Kent, *Long-Term Electricity Supply Contracts Between Utilities and Small Power Producers*, 5 STAN. ENVTL. L. ANN. 175, 179 (1983).

134. *Id.*

135. Hamilton, *supra* note 81, at 456-57.

136. *Id.*

Some jurisdictions have enthusiastically endorsed levelizing,[137] while others argue that the system unfairly requires utility ratepayers to pay capacity costs before they are actually incurred.[138]

A further persistent variation is the choice of the time period over which projections of avoided cost are made. At one end of the spectrum, Maine requires a utility to make separate avoided cost calculations for every 50 Mw per hour they can avoid due to the receipt of cogenerated power.[139] At the other end of the spectrum, some states determine avoided costs on fifteen year projections.[140]

This brief sampling indicates the plethora of issues that must be addressed in adopting a methodology for calculating avoided energy and avoided capacity costs. Also imposed on this determination is the issue of the impact of possible federal preemption; an issue which, among other things, confuses how environmental and social costs (the third compenent of avoided cost) should be calculated.

3. Preemption

The preemption issue is raised by a pair of irreconcilable decisions by the highest courts of New York[141] and Kansas.[142] Both cases considered the right of state regulatory bodies to require utilities to purchase power from federally qualifying QFs at prices above avoided cost. The Kansas court, relying on the statement in *American Paper Institute* that the avoided cost rate "applies in the absence of a waiver or a specific contractual agreement,"[143] held that there was no state right to set a higher than avoided cost rate for the purchase of QF power.[144]

In contrast, the New York Court of Appeals reversed a lower court and held that PURPA did not preempt a provision of the

137. Howe, *supra* note 103, at 57 (Washington Water Power Co., Idaho PUC, Order No. 18744 (Mar. 21, 1984)).

138. Washington Utilities and Transportation Commission v. Washington Water Power Co., Washington UTC (Nov. 9, 1983), 56 PUB. UTIL. REP. 4th 615 (1984).

139. Howe, *supra* note 103, at 57.

140. *Id.*

141. Consol. Edison Co. v. Public Ser. Comm., 63 N.Y.2d 431, 483 N.Y.S.2d 153, 422 N.E.2d 981 (1984); *appeal dismissed,* 105 S. Ct. 1831 (1985) (lack of substantial federal question).

142. Kansas City Power and Light Co. v. Kansas Corp. Comm., 234 Kan. 1052, 676 P.2d 764 (1984).

143. American Paper Inst. v. American Elec. Power, 461 U.S. 402, 416 (1983).

144. 234 Kan. at 1057, 676 P.2d at 768.

New York Public Service Law (§ 66-c) to the extent that it prescribed a uniform minimum purchase price of 6¢ per Kw hour (higher than avoided cost) for electricity purchased by a utility from facilities that qualify under both federal and state law.[145] It based its decision on an analysis of legislative history and PURPA language, finding that PURPA's avoided cost pricing was not an *absolute* ceiling on the price that could be set by *either* the federal or state authorities. Instead it was intended to set a maximum in the context of the *federal* government's role in encouraging alternative power.[146]

In March 1985, the Supreme Court dismissed, for want of a substantial federal question, an appeal of the New York Court of Appeals decision.[147] The dissent argued that "the effective, orderly and consistent administration of PURPA required that the extent [of state] authority [be] settled."[148] As of March 1986, however, such clarification is lacking.

This not only means that states may not take measures they otherwise might for fear of preemption; it also means that many existing rules regarding avoided cost calculation might be open to challenge.[149] Because estimation and forecasting, by nature, are central to any method of calculating avoided cost, it will often be the case that the approaches touched on above will result in a utility being required to pay rates above its avoided costs at certain times during the period of its contract. All such methodologies are therefore of uncertain validity in states which have not decided the preemption question.

The uncertainty created by the preemption issue spills over into the question of how the social and economic component of cost should be determined. This component of cost is made up of

145. 63 N.Y.2d at 433, 483 N.Y.S.2d at 154.

146. 63 N.Y.2d at 435, 483 N.Y.S.2d at 157.

147. 105 S. Ct. 1831 (1985).

148. *Id.* at 1832 (White, J., dissenting).

149. Appellants in the Supreme Court case pointed to ten states besides New York that had authorized or required payments to QFs in excess of avoided cost, 105 S. Ct. at 1832 (White, J., dissenting). Some commentators have concluded that states may require purchase rates in excess of full avoided costs. *See, e.g.*, Hagler, *Utility Purchases of Decentralized Power: The PURPA Scheme*, 5 STAN. ENVTL. L. ANN. 154, 163 (1983); Lornell, *A PURPA Primer*, 3 SOLAR L. REP. 31, 53 (1983). Other commentators have documented the conflicting approaches of state regulatory commissions. *See* Lock, *Statewide Purchase Rates Under Section 210 of PURPA*, 3 SOLAR L. REP. 419, 445 (1981); Lock & Van Kuicken, *Cogeneration and Small Power Production: State Implementation of Section 210 of PURPA*, 3 SOLAR L. REP. 659 (1981).

a quantified recognition that traditional power generation is over-reliant on non-renewable foreign resources and is limited in its responsiveness to demand because of inherently large baseload capacity construction patterns. These costs are avoided to some extent by utilities purchasing from QFs.[150] They are also recognized in FERC rules as a legitimate component of avoided costs.[151] Because these costs are not currently internalized by utilities, however, it is unclear how one could include them in a rate calculation and not violate the absolute ceiling of avoided cost as identified by the Kansas Supreme Court.[152]

4. Alternatives to Avoided Cost

In refining the policy regarding purchase price calculations, it is also necessary to consider the argument that avoided cost ought not to be the cornerstone of purchase rate calculation.

Net billing, for example, offers a QF the simplicity of billing only the net surplus or deficit of power that is exchanged between a utility and a QF where both the power purchased and that sold by the QF flow through a single meter.[153] FERC rules recognize that this may be an appropriate method of approximating avoided cost in some instances, especially when small QFs cannot absorb the cost of dual metering or time-of-delivery payments, but the Commission has refused to require such billing under any circumstances.[154]

Others are beginning to reargue that avoided cost calculated prices do not give sufficient incentive to utilities to purchase additional QF power.[155] A split difference pricing is one alternative.[156] Under such a system the QF and the utility would split the difference between the QF's generation costs and the utility's avoided costs, thus affording some profit to each entity. Though split difference pricing has been rejected by FERC with Supreme Court approval[157] as contrary to the Congressional intent to

150. Hamilton, *supra* note 81, at 461-62.

151. 18 C.F.R. § 292.304(c)(4)(iii) (1985).

152. 243 Kan. 1052, 676 P.2d at 768. *See also* Hamilton, *supra* note 81, at 459-60.

153. Wooster, *supra* note 2, at 743.

154. 45 Fed. Reg. 12,224 (1980).

155. Einhorn, *Avoided-Cost Pricing: Who Wins*, PUB. UTIL. FORT., May 30, 1985, at 35.

156. *Id.*; Wooster, *supra* note 2, at 743.

157. American Elec. Power Service Corp. v. FERC, 675 F.2d 1226, 1234, *rev'd on other grounds sub nom.* American Paper Institute, Inc. v. American Elec. Power Serv., 461 U.S. 402 (1983).

avoid public utilities-style rate setting, it has been argued that a split-the-difference type scheme could legitimately be operated through a tax on QF net revenues, through an upfront sellers fee leveled on each QF, or through pricing some blocks of power sold by a QF at lower than avoided cost.[158]

The preferred methodology for determining the rate a utility must pay for QF electricity will balance the fairness of the method to utility ratepayers, the usefulness of the method as an incentive to small power producers and the verifiability of the method. Arguably, these competing interests also need to be balanced in the light of a policy that minimizes the proliferation of approaches while satisfying the need for context-specific flexibility.

B. *How to Improve the Bargaining Power of QFs*

Though PURPA sought to impose requirements of cooperation on utilities, it has been argued that PURPA paid inadequate attention to the entry barriers faced by QFs, including the unequal power relationships between utilities and QFs. This section addresses the arguments that such barriers could be lessened by 1) decreasing information and financing costs that fall upon QFs, 2) facilitating bargaining by more standardized contracts, and 3) promoting QF markets by wheeling.

1. Information and Financing Costs

Even before obtaining qualified status, barriers such as information costs and financing costs exist. The costs of acquiring the expertise and information necessary to plan and manage this type of venture can be prohibitive for many potential QFs, especially those in the small power producer category. Government research and development funding could help this situation in the long run, but recent years have not experienced generous appropriations in this area.[159] One innovative approach would place the responsibility for assisting potential QFs in this regard on the utilities. In California, for example, the regulatory commission ordered the largest utility under its jurisdiction to study cogeneration potential and to assist cogenerators in analyzing the legal,

158. Einhorn, *supra* note 154, at 36.

159. Furthermore, current federal policy and oil price reductions will most likely only decrease the amount of funding available for cogeneration and other alternative energy power production research.

environmental and cost factors relevant to their investment decisions.[160]

The cost of financing can act as a disincentive since small-scale power facilities involve a high initial capital investment. Some states have put in place or are considering programs to provide low interest loans from public funds,[161] interest subsidies on private loans,[162] or mandatory low-interest financing by the utilities.[163] Some alleviation of this difficulty may result from greater experience with innovative leasing and shared savings techniques.[164]

2. Contracts

Once a potential QF has undertaken business and become qualified, more hurdles await, not least of which is that a contract must be negotiated with the purchasing utility. As noted above, FERC rules explicitly allow for independently negotiated contracts between utilities and QFs.[165] States very in the extent to which they impose restrictions on the substance of such contracts,[166] but still the negotiations between an utility and a small power producer are a key to the implementation of PURPA's policy to encourage alternative power production. In these negotiations, the QF is often an unequal partner.

In the absence of wheeling,[167] the facility may have no alternative buyer for the power produced making terms offered by the utility acceptable of necessity.[168] In addition to the market inhibition which prevents the shopping around for another deal, the small power producer is handicapped by a lack of information and

160. T. STEIN, THE PATH NOTE TAKEN: A COMMON CAUSE STUDY OF STATE ENERGY CONSERVATION PROGRAMS 103 (1980).

161. Field, *Power to Spare*, FORBES 78, 79 (Jan. 31, 1983).

162. N.Y. State Energy Office, 1 N.Y. State Energy Master Plan, Draft Report for 1983 at 45, 71-72 (1983) [hereinafter cited as N.Y. Plan for 1983] (recommending expansion of EILP, which provides subsidies for conservation investments).

163. *Id.* at 37, 71-72 (recommending expansion of HIECA, which requires utility financing of conservation measures).

164. *Id.* at 71. In shared savings transactions, a third party investor purchases the equipment for the cogenerator for a share of the energy savings. *Id.* at 51.

165. *See* text accompanying note 55.

166. *See, e.g.*, Hagler, *supra* note 29, at 162-163 (Oregon PUC approved a purchase price above avoided cost); Lock & Van Kuieken, *supra* note 149, at 677 (New Mexico PUC prohibits contracts which call for purchase rates above full avoided cost.)

167. *See infra* note 192 and accompanying text.

168. *See infra* text accompanying notes 192-213.

experience. In negotiations, the party with superior information on the issue usually has the advantage. This advantage is held by the utilities in two ways. Because the utilities engage in a large number of transactions of the same type, they are able to spread the fixed costs of collecting information over a number of contracts. The utility's cost of obtaining information per contract negotiation therefore will be lower than the cost to the small power producer who engages in few such transactions. In addition, the utility already has the needed data and employs skilled personnel. Small power producers who are new to the field must invest resources in learning and developing data.

Acknowledging this imbalance of power, state commissions intervene in the negotiation process to varying degrees. There is a need to assess which methods are most effective in counteracting the force called utility monopsony power.[169]

Four state approaches have been identified:[170]

1. The parties negotiate contracts. The commission does not review the contract unless one of the parties protests.[171]
2. The parties negotiate contracts subject to approval by the state utility commissions.[172]
3. Each utility issues standard contracts which must be approved by the utility commission.[173]
4. The utility commission mandates a standard contract for use by all the utilities in the state.[174]

The first two approaches are arguably too onerous for QFs and may act as disincentives to QF development. Filing a protest is time consuming and expensive.[175] Similarly, Commission approval will cause substantial delay if review is effective.

The fourth option, the standard contract, is proposed as particularly suitable for small producers with capacity under 100 Kw.[176] Although the contracting problems posed by the utility's monop-

169. Where there is a single buyer of an input, a monopsony exists. Hamilton, *supra* note 81, at 434.

170. *Id.* at 440-441 (citing RESOURCE DYNAMICS CORP., STATE RULEMAKING AND UTILITY PRICING FOR COGENERATION 1, 14 (1983)).

171. *Id.* Texas and Illinois handle contracts this way.

172. Florida is an example of this approach. Telephone interview with Stan Hvostik, Electric and Gas Department, Florida Public Service Commission (Jan. 30, 1986).

173. California is an example of this approach. See *infra* text accompanying notes 180-86. Idaho also endorses, though it does not require the submission of standardized contracts, Re Washington Power Co., 59 PUB. UTIL. REP. 4th (PUR) 103, 112 (1984).

174. Hamilton, *supra* note 81, at 441.

175. *Id.*

176. *Id.*

sony power apply to relatively larger power producers as well, at some point the size of the investment in an alternative energy project should be sufficiently large so as to overcome the utility's cost and overall resource advantages.[177] The Minnesota statute recognizes small power producers under 40 kw capacity as needing the protection of a standard contract, while one of California's Standard Offers is directed at the particular needs of facilities with 100 kw capacity or less.[178] This option consolidates the input of utilities and small power producers into one proceeding and minimizes the demands on the scarce resources of staff and commissioner time.[179] A uniform contract issued by the state also reduces the overall costs incurred by all parties while increasing the simplicity of the operation, a factor which especially benefits small producers who may thus avoid attorney or expert fees. Parties need only, for example, fill in the purchase price, the manner of payment and the term of the contract.

California has adopted the third option, multiple standard offers, as a means, in part, of regularizing the use of various avoided cost formulae.[180] The California Public Utilities Commission (CPUC) established guidelines under which standard offers are made to QFs who can produce energy under one of the five plans: the "as available" plan, the "less-than-100-Kw" plan, the "firm capacity" plan based on specific performance requirements, a "five-year forecast" plan, offering fixed energy prices, or the "long-run resource" plan.[181] The utilities were then asked to respond to these categories by designing standard offers. As a result of compliance hearings,[182] QFs seeking to sell to one of the three largest California utilities may chose from four standard of-

177. *Id.* at 440.

178. MINN. STAT. ANN. § 216B.164 (1982). Regarding California, see *infra* text accompanying note 180.

179. Hamilton, *supra* note 81, at 441.

180. *See* Howe, *supra* note 103, at 56, and Kent, *supra* note 133, at 179.

181. Kent, *supra* note 133, at 179-84.

182. Cal. P.U.C. Decisions D-82-12-120 (Dec. 30, 1982) (first of two decisions resulting from compliance hearings in PG&E, SCE and SDG&E Standard Offers 1, 2 and 3 filed in response to D-82-12-120); D-83-09-054 (Sept. 7, 1983) (approval of Standard Offer 4 for PG&E, SCE and SDG&E); D-83-10-093 (Oct. 19, 1983) (second decision from compliance hearings for Standard Offers 1 and 2); D-84-03-092 (third decision from compliance hearings on Offers 1 and 2); D-84-04-012 (April 4, 1984) (fourth decisions on Standard Offers 1 and 2); D-85-07-021 (July 10, 1985) (suspension of Standard Offer 4 continued).

fers, although one Standard Offer was suspended by the Commission until further notice in April, 1985.[183]

Standard Offers 1 and 3, the "As-Delivered Capacity and Energy" offer and the "As-Delivered Capacity and Energy from QFs Less than 100 Kw" offer, are much the same except that the latter is simplified to accommodate very small producers. Under them the QF's energy and capacity are sold on an as-available basis, not firm, meaning that the amount and time of delivery of the energy is not guaranteed. The QF is paid full short-run avoided energy cost, plus current shortage cost, on a per/Kwh basis, for all energy delivered to the utility. These costs are updated quarterly by the utilities, with the energy cost based on the incremental energy rates (IERs) established in the last rate case and the expected fuel costs for the quarters. Shortage costs are based on the cost of a combustion turbine. This contract is used by all technologies, particularly wind, due to the uncertain nature of that resource.

Under Standard Offer 2, the "Firm Capacity and Energy" offer, the QF's capacity is sold on a firm basis, meaning that an amount of capacity is guaranteed to be available to the utility during its peak load period. The capacity payments are based on levelized, forecasted shortage costs, which are stated in the contract and are fixed for the life of the contract. Energy prices are the same as in Standard Offer 1. This offer appeals principally to cogenerators, biomass and small hydro QFs who need a relatively high and stable return on their investment early in the term due to the risk of technological failure, which is greatest at that time, and to the need to meet the security requirements of creditors.[184]

The "Long Term Capacity Energy" standing offer has been the most controversial. As of February 1, 1986 it was indefinitely suspended. This offer provides fixed payment rates over long time spans (up to ten years) to provide QFs with some certainty in the return on their investments. There are three energy payment options and two capacity options in this offer:

183. Cal. PUC D-85-04-075 (April 17, 1985) (suspension of Standard Offer 4); D-85-07-021 (July 10, 1985) (suspension of Standard Offer 4 continued). Suspension was still effective as of February 3, 1986 according to telephone interview with W. Flaherty, California PUC (Feb. 1, 1986).

184. Kent, *supra* note 133, at 187. The costs of financing the large initial investments involved are a major obstacle to QF development. Another reason given for the need for higher early investment recovery is the perception by QF owners that power production is a "nonessential" operation and must be extraordinarily profitable to justify the investment. Wooster, *supra* note 2, at 765.

Energy Option 1: energy prices are fixed and are based on forecasted avoided energy costs. The QF can choose to have a mix of forecasted and current short-run avoided costs for the energy price, with oil and gas fired cogenerators limited to twenty percent of the price being based on the forecasted prices.

Energy Option 2: this is similar to Option 1, except that the forecasted energy prices are levelized and oil and gas fired cogenerators may not use this option at all.

Energy Option 3: energy prices are based on fixed, forecasted utility IERs and utility oil and gas costs. Payments are made based on short-run costs, then adjusted at the end of the year to reflect the forecasted prices. This option is used by cogenerators and is designed to have the energy price reflect changes in fuel costs.

Capacity Option 1: as delivered: the QF can choose payments based on either short-run shortage costs updated quarterly, or fixed, forecasted shortage costs, which are not levelized.

Capacity Option 2: firm: payments are based on fixed, forecasted, levelized shortage costs.

While some of these standard offers contain liquidated damages clauses and others do not, if a breaching QF fails to pay either the foreseeable damages or some specified minimum damages, the utility is released from its obligation to contract with the QF.[185]

California has also set up procedures in three areas for regulatory review of contracts negotiated individually when a QF chooses not to accept any of the standard contracts. The aim of this supervision is to ensure good faith bargaining while keeping regulatory and transaction costs to a minimum. First, the CPUC will review and approve all contract terms. Upon approval, a term is designated as "reasonable" and the utility may therefore pass any costs arising under the term on to its ratepayers. Second, in general rate case proceedings the CPUC will review each utility's creativity and consider its initiative in signing small power producers."[186] Third, the CPUC has considered allowing the utilities to receive "brokerage fees" in the form of a reduction in purchase price.[187]

185. Kent, *supra* note 133, at 185 n.59. One might question whether this runs afoul of the basic policy of PURPA and the regulations promulgated under it.

186. *Id.* at 188.

187. *Id.* at 188-89.

The chief purpose of CPUC review seems to be to ensure the reliability of a QF where the contract terms call for greater risk to be assumed by the ratepayers, through the utility, than would be present under the standard contracts.[188] Examples of such terms are: the utility's obligation to pay despite nonperformance or incomplete performance; price levelization;[189] price floors and ceilings, sometimes with arbitration or renegotiation provisions if a price based upon fluctuating fuel prices reaches the floor or ceiling; and payment tracking accounts, which effectively establish a fixed price above SRMC for early contract payments.[190] This multicontract option which has been so successful in California might be of more limited use where numerous municipal and cooperative utilities operate in small service areas, for its complexity and review requirements could invite delay.[191] In any case, a systematic review of workable contract procedures and clearer policy on their use is called for.

3. Wheeling

The ability of a QF to sell its power at the best price available is dependent upon whether the power may be delivered to the buyer. Wheeling, transmission over the lines of a third-party utility, is one means of expanding the spectrum of potential buyers. By this technology, QFs located within the service area of a utility with relatively low avoided costs, as, for example, where there is excess capacity, could obtain access to other utilities or retail customers offering higher purchase rates. To the degree that the power supplied by a QF displaces power generated at a higher incremental cost, these wheeling transactions promote economic efficiency.[192] Thus, where a utility has recently completed construction of a large power plant, retail rates will rise to pay for the

188. *Id.* at 188.

189. *Id.* at 190. Kent asserts in a footnote that the CPUC "refused to incorporate [price levelization] into the standard contracts." *Id.* at 190, n.81.

190. *Id.* at 189-91. Kent's description of the payment tracking accounts (PTAs) is somewhat unclear. One interpretation of it is as follows: For a set early period of the contract, payments are levelized. The difference between the levelized price and 97% of SRMC goes into the PTA, which is an interest-bearing bank account, the interest going to the QF. When 97% of SRMC rises above the level purchase rate, the QF gradually depletes the PTA as it delivers power. If the QF defaults, it forfeits to the utility any remaining balance in the PTA. *Id.* at 191. *See* CPUC Decision 82-04-087 (1982).

191. Hamilton, *supra* note 81, at 441.

192. Pfeffer, *Policies Governing Transmission Access and Pricing: The Wheeling Debate Revisited*, PUB. UTIL. FORT., Oct. 31, 1985, at 26, 27.

new plant. At the same time the utility's avoided costs are likely to fall because excess capacity is available. If QFs in the area were able to transmit their power, they could supply less expensive electricity directly to consumers and also make a profit.[193]

The benefits of wheeling QF power are not restricted to QF profits. In order for a state to derive the maximum benefit from QF capacity, power produced by QFs should be made available to utilities which need additional generating capacity.[194] By channeling geographically dispersed QF capacity to the utility with the most urgent need for it, "the expansion plans of one utility may be significantly altered by the aggregate impact of all firm QF capacity in the state,"[195] as opposed to the very slight impact QF capacity would have on the expansion plans of many utilities scattered throughout the state. Most wheeling is done on a contractual basis,[196] since PURPA does not mandate wheeling but allows interconnected utilities to wheel QF energy to another utility if the QF consents.[197]

Regulations, however, also reserve to FERC the general authority to order wheeling from one utility to another upon application from an electric utility or a federal marketing agency.[198] However, certain stringent criteria must first be met.[199]

These criteria are designed to ensure that wheeling enhances economic efficiency, improves the reliability of service, preserves existing competitive relationships and is not an undue burden on the wheeling utility. They have been subject to criticism as being too stringent to allow sufficient response by FERC. Charles Stalon, Commissioner of the FERC, has stated, for example, that these criteria require the FERC "to pass through the eye of a needle before it can impose wheeling on a utility. The Commission has not yet found that opening."[200]

193. Munson, *supra* note 14, at 16.

194. This is the approach of the Florida cogeneration rules expressed in Re Cogeneration Rules, 68 PUB. UTIL. REP. 4th (PUR) 112 (1985).

195. *Id.* at 113. To implement this statewide utilization of QF power, the Florida Public Service Commission requires utilities to wheel QF electricity to other utilities.

196. Pfeffer, *supra* note 192, at 29.

197. 18 C.F.R. § 292.303(d) (1985).

198. 16 U.S.C. § 824(j) (1982) (1978 amendment to Part II of the Federal Power Act).

199. 16 U.S.C. § 824(j), (k); 834(i) (1982).

200. C. Stalon, Some Thoughts and Concerns About FERC Wheeling Policies, (address delivered at the Mid-Year Meeting, Federal Energy Bar Association) (Jan. 10, 1985). *See, e.g.*, the FERC's refusal to order wheeling from "Kentucky Utilities" to eight municipally owned utilities, despite a request by the Southeastern Power Administration. (FERC

In May 1985, FERC issued a notice of inquiry with the stated objective to "evaluate how its policies promote, or whether they impede, efficiency in electricity markets and to determine whether there are available alternatives to or possible revisions of these policies which could further promote efficiency in the electric utility industry."[201] One commentator believes that this inquiry may indicate FERC's interest in providing incentives for increased transmission service as a means of developing competitive markets.[202] Among the questions presented for comments were the following, which speak to the special concerns of QFs: whether the demand for transmission services is being met; how the existing pricing policies of the FERC affect utility incentives to provide wheeling service voluntarily; and the efficiency implications of various types of transactions and alternative transmission access policies.[203] The inquiry notice and the thrust of recent comments by the chairman and members of the Commission inspire speculation as to the future direction of Commission policy in the transmission area.[204] Although the policy is likely to encourage more competition in the electricity market, the Commission may be expected to remain cautious about any changes which might impede economic efficiency or penalize the customers of the wheeling utility.[205]

The legislative history of PURPA generally supports the FERC's understanding of the limited scope of its authority to mandate wheeling. Although the House version of PURPA included extensive mandatory wheeling obligations, the legislation ultimately developed by the Conference Committee gave very limited authority to mandate wheeling by the FERC.[206] Since then, legislation dealing with transmission access policy has been introduced in Congress on several occasions but has never

Docket No. D180-7-000, Opinion No. 198) (reported in COGENERATION AND SMALL POWER MONTHLY, Jan. 1984, at 4). In this case, the FERC concluded that neither the FPA's wheeling provisions nor PURPA's were designed to give the FERC new authority to remedy anti-competitive conduct.

201. Regulation of Electricity Sales-for-Resale and Transmission Service, 50 Fed. Reg. 23,445 (1985).

202. Pfeffer, *supra* note 192, at 32.

203. A public conference on the NOI was held September 18, 1985. Transcripts are available from the FERC's Office of Public Information.

204. Pfeffer, *supra* note 192, at 32.

205. *Id.* at 33.

206. 16 U.S.C. § 824(j) (1982). *See supra* text accompanying notes 190 to 191.

passed.[207] The failure to mandate wheeling may be understood as an affirmative statement that the Commission has properly interpreted the role Congress intended it to play, but the persistence of Congressional initiatives may indicate otherwise.

As a result of FERC's reluctance to order wheeling, some states took up the effort, particularly with respect to cogenerated power from QFs.[208] For example, in May 1984, the Florida Public Service Commission (FPSC) issued an order which requires wheeling of QF power to other utilities at an interim rate of 1 mill/Kwh.[209] The 1 mill rate was only 1/3 to 1/2 of the rate applicable to wheeling which is on file at the FERC, and was set low in a deliberate attempt to encourage the viability of cogeneration. Further, the FPSC stated its policy to prohibit wheeling charges entirely when transmission capability is available and no additional costs would be incurred by the utility.[210] The FPSC requested a declaratory opinion from the FERC as to who had the authority to establish rates for the intrastate wheeling of QF produced electricity.[211]

In October 1984, the FERC responded to the FPSC request in an order which held that the FERC had exclusive and preemptive jurisdiction to set wheeling rates for transmissions occuring in "interstate commerce."[212] "Interstate commerce" is broadly interpreted to include many purely intrastate transactions, if they are part of an interstate network.[213] Only facilities used solely for local distribution are subject to state jurisdiction.[214]

207. *See, e.g.*, H.R. 2231, 99th Cong., 1st Sess. (1985); H.R. 1815, 99th Cong., 1st Sess. (1985) (both referred to the Committee on Energy and Commerce).

208. States which ordered intrastate wheeling include New Mexico, Florida and Texas. Pfeffer, *supra* note 192, at 33.

209. FLA. ADMIN. CODE Rule 25-17.835 requires utilities to wheel; Docket No. 830377-EU, Order No. 13247 (May 1, 1984), set the wheeling rate.

210. *Id.*

211. *FERC Issues Declaratory Order on Wheeling Question*, Cogeneration Monthly, Nov. 1984, at 1.

212. 29 F.E.R.C. ¶ 61,140 (Oct. 31, 1984).

213. Interstate commerce as defined in § 201(c) of the FUA "has been consistently interpreted to mean that the Commission has jurisdiction when the system is interconnected and capable of transmitting energy across the State boundary, even though the contracting parties and the electrical pathway between them are within one State." 29 F.E.R.C. ¶¶ 61,285, 61,291.

214. Some uncertainty remains as to the extent of state jurisdiction because the FERC has not yet applied the ruling issued in 29 FERC ¶ 61,240 because declaratory orders do not address the facts of a specific situation. Following the FERC decision, the FPSC left the 1 mill rate in place on intrastate transactions and recommended that any questions as to whether a particular transaction occurred in inter- or intrastate commerce be resolved in the first instance by the FERC. Re Cogeneration Rules, 68 PUB. UTIL. REP. 4th (PUR)

Having decided that Florida had no jurisdiction to set wheeling rates on interstate transactions, the FERC stated it would not necessarily defer to the state policies, but would merely "give weight" to state rates during the approved process, provided they did not violate public policy, such as the policy against undue discrimination.[215] Moreover, FERC found that preferential rates to QFs are presumptively discriminatory, and the FERC said that the FPSC would have a "heavy burden" if it tried to justify this artificial subsidy to QFs.[216]

A question not directly raised by the case, and therefore not decided by the FERC, was whether states have any authority to order wheeling, regardless of who sets wheeling rates.

Although the FERC's assertion of exclusive jurisdiction over wheeling rates is unfortunate where states would use preferential wheeling rates as incentives to cogeneration and renewable resource production, one analysis suggests that creative use of the decision may turn it to the advantage of small power producers:

> While on its face, the presumption against preferential rates is negative from the point of view of cogenerators, it may well end up a substantial plus. The Commission has suggested that utility rates and practices cannot be unduly discriminatory under Section[s] 205 and 206 of the Federal Power Act. If a utility has a filed wheeling tariff, or even wheels under contract for other utilities, that wheeling precedent, together with the Commission's ruling concerning preferential treatment, may lay the groundwork for an action under section 206 by a cogenerator against a utility which offers 'preferential' terms to other utilities.[217]

Thus, there is the possibility that the FPSC case may provide a route to actions which force utilities to give fair treatment to cogenerators. If equal treatment of all wheeling requests is to be guaranteed, QFs will be better able to compete with utilities for transmission services of those utilities who have voluntarily chosen to wheel power. In light of the FERC's reluctance to order wheeling and the questions concerning a state's jurisdiction to order wheeling, equal access may be more important than the mar-

112, 114 (Docket No. 830377-EU, Order No. 14339, May 2, 1985). No challenges had been filed as of February 1986, Telephone interview with S. Hrostilc, Florida Pub. Service Commission Electric and Gas Department (Mar. 1986).

215. 29 F.E.R.C. ¶ 69,285, 61,293.

216. *Id.*

217. *FERC Issues Declaratory Order, supra* note 211, at 3.

ginal economic advantage offered by FPSC's preferential wheeling rates for QFs.

Another significant obstacle to effective federal requirements ordering utilities to wheel power is the "staggering"[218] complexity of properly pricing wheeled power. Such pricing depends upon sensitive analysis of time and place of both supply and demand; mere averaging of costs may not only fail to reflect true costs, but may result in an inefficient and uneconomic use of power by consumers.[219] As with avoided cost calculations, an understanding of methodologies and an articulated policy regarding them is needed.

C. *How to Increase Utility Cooperation*

Aside from the lack of cooperation that small-scale producers experience generally when dealing with the utilities, a QF may also face a certain amount of state protectionism. Concerned with the reliability of the power grid and with keeping electric rates down, state commissions have been cautious about requiring or even allowing the utilities to take certain risks.[220]

A responsible state commission will never lose this concern. However, there are measures which can be taken to overcome the reluctance of the utilities. One alternative is to condition a utility's rate of return on the utility's solicitation of contracts for a minimum amount of QF-generated capacity by a stated deadline. The California PUC, for instance, reduced Pacific Gas and Electric (PG&E) authorized rate of return on equity by 0.2% because it failed to make an effort to promote cogeneration.[221] Furthermore, the Commission refused to raise the rate unless PG&E signed contracts for at least 600 Mw of new cogeneration capacity within the following two years.[222]

Another method of reducing utility hostility to small-scale power production is to let utilities own controlling interests in

218. Stalon, *supra* note 200.

219. *Id.* (citing Bohn, Caramis & Schweppe, *Optimal Pricing in Electrical Networks Over Space and Time*, 15 RAND J. OF ECON. 360 (1984)).

220. *See* Comment, *A Look at Federal and State Cogeneration and Small Power Production Regulations*, 3 J. ENERGY L. & POL'Y 329, 345 (1983) (discussing a Utah utility's right to disconnect whenever its system is adversely affected by the QF).

221. *See In re* Pacific Gas & Electric, 34 PUB. UTIL. REP. 4th (PUR) 114 (1979).

222. *Id.* Allowing an increased rate of return on investments in cogeneration and other conservation technology is an allied approach, though it focuses on incentives to utilities rather than on incentives to independent producers. *See* Stearns, *supra* note 19.

QFs. If Congress amended PURPA to render facilities in which utilities have a majority interest eligible for qualifying status, the utilities would have an incentive to set more favorable purchase rates.[223] In addition, enhanced expansion of cogeneration markets is likely to result from the extension of PURPA benefits to utilities.[224] Among the reasons why utilities are more likely to develop cogeneration markets than fuel users is their superior experience in electricity generation, lower requirements for return on investment, and concern for loss of sales to industrial customers who might install cogeneration equipment.[225]

The whole question of the degree to which utilities should become involved in the decentralization of our power supply has generated some debate. While allowing utility participation may increase overall efficiency, it may also enable utilities to reacquire a monopoly over the power industry.[226] A 1983 report issued by the Office of Technology Assessment concluded that with careful precautionary measures, the benefits of utility ownership would probably outweigh potential anticompetitive effects.[227]

Utility participation could be effectuated in several ways. Legislation has been introduced which would eliminate the restriction on utility equity interest in qualifying facilities, thereby extending PURPA benefits to utilities either uniformly,[228] or by FERC waiver where no anti-competitive effects were found.[229] Alternatively, the FERC interpretation of what constitutes 50% equity interest could be changed to permit utilities to enter into partnerships which own the QFs. Currently, the Commission in-

223. *Utility Role in Cogeneration and Small Power Production: Hearings Before the Subcomm. on Energy Conservation and Power of the House Comm. on Energy and Commerce*, 97th Cong., 1st Sess. 175 (1981) (statement of Thomas R. Casten, President, Cogeneration Development Corp).

224. "Under utility ownership, economic industrial cogeneration potential has been demonstrated to be approximately 35 percent greater than in the case of industrial ownership." Scranton, *Reforming and Improving Electric Utility Regulation*, PUB. UTIL. FORT., Aug. 4, 1983, 19, 22 (citing SYNERGIC RESOURCES CORPORATION, ASSESSMENT OF INDUSTRIAL COGENERATION IN PENNSYLVANIA (Governor's Energy Council) (Jan. 1983)).

225. Numark & Cooper, *Prospects for Utility Ownership of Cogeneration*, PUB. UTIL. FORT. Feb. 2, 1984, at 25.

226. Hagler, *supra* note 29, at 173. *See also* Gentry, *supra* note 22, at 324-344.

227. OFFICE OF TECHNOLOGY ASSESSMENT, U.S. CONGRESS, INDUSTRIAL AND COMMERCIAL COGENERATION (1983).

228. *See* H.R. 2876, 97th Cong., 1st Sess. (1981) (by Rep. William Alexander (D-Ark.)).

229. *See* H.R. 2992, 97th Cong., 1st Sess. (1981) (by Rep. Cecil Heftel (D-Ha.)); and S. 1885, 97th Cong. 2d Sess. (1981) (by Senators Bennet Johnson (D-La.) and Gordon Humphrey (R-N.H.)).

terprets Section 210 of PURPA literally, thereby restricting the advantages of qualifying status to facilities which are not owned primarily by electric utilities or their subsidiaries.[230] There was a brief period during which it was perceived that FERC had adopted an interpretation which emphasized control as well as ownership. Thus, FERC approved a partnership between a subsidiary of the Tucson Electric Power Co. and a private company where the utility subsidiary contributed 67% of the initial capital for the partnership in the form of debt.[231] The partnership agreement provided, in addition, that each partner would have a 50% interest in profits and losses and 50% of the voting power. Because the profits, losses and management of the venture were shared equally, the stream of benefits and control of the partnership were found dispositive as to equity interest and qualifying status was awarded.[232] A subsequent proposal to remove the utility from control through a two-tier partnership plan was denied qualifying status because the utility would potentially contribute 99% of the capital and earn 99% of the profits. FERC emphasized that "it is the investment in and realization of gain from the venture and not merely the exercise of control that determines the equity interest."[233]

Other forms of limited partnership could also be explored. One variation, for example, entails utility or utility subsidiary-ownership of a third-party company which cogenerates electricity on the site of an industrial, steam-using firm. Such an arrangement allows the third-party firm to sell electricity to the utility for full avoided costs. If it can produce electricity at less than that price, the profit may be used to provide discounted prices for steam-supply to the industrial concern.[234] This scheme also provides an incentive to invest in cogeneration systems which generate a higher electricity-to-steam (E/S) ratio, because the utility is

230. K.P. Diversified Investors Inc., 32 F.E.R.C. ¶ 61,0147, 67 PUB. UTIL. REP. 4th (PUR) 563, 568 (1985).

231. Ultrapower 3, 27 F.E.R.C. ¶ 61,182 (1984).

232. *Id.*; K.P. Diversified, *supra* note 230, clarifies the current policy regarding interpretation of the equity interest limitation.

233. K.P. Diversified, *supra* note 230 at 568.

234. *See* R. Williams, Removing Regulatory Barriers to Cogeneration 12 (testimony, representing the Princeton University Center for Energy and Environmental Studies, before the Subcommittee on Energy Development and Applications of the Committee on Science and Technology, July 22, 1980) (available in the office of the Columbia Journal of Environmental Law).

more interested in supplying electricity to its customers than in providing steam to the industrial user.[235]

All of these models of utility participation in cogeneration and small power production offer utilities an opportunity to earn profits in a non-regulated market,[236] with far lower capital investment than that required for new central plants. This is particularly important now, as utilities stagger under the construction costs for nuclear plants, some of which will never be completed.

Utility involvement, however, poses the threat of anti-competitive effects, such as deterring smaller producers, impeding private sector innovation of new cogeneration system designs, distorting the fuel market as utilities make bulk purchases of one or another fuel for their cogenerating stations, and tying-arrangements or manipulative pricing tactics between a utility and its cogenerating subsidiary.[237] Any attempt to amend PURPA to allow utilities to own significant interests in QFs will require very detailed drafting that addresses these problems.

D. *Managing the Conflict Between Cogeneration and Air Quality Control*

California has recognized this difficulty and responded by adjusting the air quality permit process for cogenerators.[238] Some suggest that an office be created within the Department of Energy to spot such conflicts, and to coordinate federal policies in order to avoid them.[239]

235. Currently, high E/S ratio technologies must be fired by oil or gas. The Office of Technology Assessment predicts that eventually solid fuels such as biomass, or coal when used in conjunction with fluidized bed combusters, will be able to guarantee high E/S ratios as well. *See* Office of Technology Assessment, Cogeneration Could Help Reduce Costs, Increase Energy Efficiency (News Release March 1, 1983).

236. Many states regulate steam sales, posing some problems under third-party arrangements. Williams, *supra* note 234, at 13 at n.24. The FERC states it does not have the authority to exempt cogenerators from such state regulation. 44 Fed. Reg. 38,865, n.5 (1979).

237. *See Hearings on S. 1885 and S. 1966 Before the Subcomm. on Energy Regulation of the Senate Comm. on Energy and Natural Resources*, 97th Cong., 1st Sess. (1981) (Written Testimony of the Cogeneration Coalition, Inc. on the Role of Electric Utilities in Cogeneration). *See also* Stearns, *supra* note 19.

238. Wooster, *supra* note 2, at 764, n.358.

239. *Id.* at 769-70. Another example of a regulatory disincentive, now corrected, were the provisions of FUA which required all feasible conversion of major fuel burning installations from oil and gas to coal. Gas and diesel topping engines save more fuel than any other type of cogeneration, produce a higher electricity-to-steam ratio than conventional boilers, are economical in small plant sizes and are environmentally cleaner than coal-fired

The Californian experience with respect to conflicts between air pollution control and encouraging cogeneration is very instructive. California has struggled with the problem since 1978, and finally settled on a complex solution which is not yet sure of federal approval. Its solution is to trade emissions from cogeneration stations with emissions from the recipient of thermal energy; to allow cogenerating stations to exceed emissions limitations in exchange for a promise to reduce emissions during future rehabilitations; and to amend state implementation plans under the Clean Air Act by use of growth allowances to offset new emissions from cogenerators.[240] These techniques pose significant problems under the Clean Air Act's provisions governing non-attainment areas and new source performance standards.

It is instructive to trace California's efforts to resolve these problems because they demonstrate precisely how complex legislative drafting may become when one must coordinate a state response to several different federal initiatives. As described earlier in this article, California has actively promoted cogeneration. In 1978, the California legislature specifically exempted cogeneration projects from regulation as public utilities.[241] Under orders issued in January 1978 by the California Public Utility Commission, California electric utilities dropped their standby charges to cogenerators by as much as 70% and filed price schedules reflecting full avoided costs.[242] The result was to encourage buy-and-sell arrangements whereby cogenerators made a profit on their more efficient production of electricity and utilities obtained electricity at a price which reflected the full purchase cost of power it would ordinarily obtain elsewhere.[243]

To forestall regulatory conflicts that might discourage the development of cogeneration facilities, then Governor Brown formed a task force consisting of representatives from the Air Resources Board (ARB), California Energy Commission (CEC), Public Utility Commission (PUC), Office of Planning and Research (OPR), the Business and Transportation Agency (BTA),

boilers using current combustion technologies. Today, cogenerators involved in simultaneous buy-and-sell are exempt from these FUA provisions.

240. One of the most thorough reviews of cogeneration legislation is California is contained in M. Ledwitz, Cogeneration in California: A History of Legislative and Regulatory Actions (June 1, 1984) (available in the office of the *Columbia Journal of Environmental Law*).

241. CAL. PUB. UTIL. CODE § 216 (West Supp. 1986).

242. Ledwitz, *supra* note 240, at 3.

243. *Id.* at 3, 4.

potential cogenerators and the utilities. The ARB took the lead and developed a model rule directing local air pollution districts to promote cogeneration by utilizing the growth allowances allowed in the California State Implementation Plan to reduce the emission offsets required of cogenerators.[244] In 1979, the California legislature enacted Assembly Bill 524, requiring air pollution control districts to issue permits to new cogeneration projects if they met the following criteria:

1. The project produces 50 megawatts (Mw) or less;
2. A project creating a net increase in emission utilizes the appropriate degree of pollution control technology required by the new source review standards of the district; if there is no net increase in emissions, the project complies with all applicable emission limitations; and
3. The project applicant does not own or operate any other facility within the air basin which could be modified to offset the new emissions from the cogeneration project. Applicants with other facilities would be required to provide such offsets.[245]

The purpose of the legislation was to assist small projects unlikely to have the funding or access to provide their own offsets. Offsets under this statute would be provided by the local air quality district by use of growth allowances generated by increased control of other sources. The concept was acceptable to EPA because the Clean Air Act authorizes local governments to provide for mitigation of impacts from projects with community-wide benefits by the use of growth allowances.[246] California began implementation of this strategy by inventorying its existing pollution sources and its potential cogeneration and resource recovery projects.[247]

In mid-1980, the ARB issued an "Inventory of Potential Cogeneration Technology and Resource Recovery Projects Planned or Proposed to be Constructed Before 1987," which showed a potential of 1,222-1,569 Mw of cogenerated power, 600-900 Mw of which would be generated by sources covered by AB 524. However, cogenerators did not move quickly to take advantage of AB 524, partly because there was confusion over im-

244. *Id.* at 4, 5.
245. *Id.* at 5-6.
246. *Id.* at 6.
247. *Id.* at 7.

plementation of the offset provisions.[248] To further encourage cogeneration, the South Coast Air Quality Management District (SCAQMD) developed the concept of "negative banking" using "paper offsets." It granted offsets, kept a record of the offsets granted and required projects to pay back the offsets during the future plant modifications or when the project obtained new corporate resources providing offset opportunities.[249]

Later in 1980 and again in 1981, the ARB issued status reports on cogeneration projects.[250] There was still a sluggish response to AB 524, and further, EPA had indicated that the SCAQMD scheme of paper offsets may violate the Clean Air Act if used for projects sited in non-attainment areas. Such areas are required to direct all new mitigation efforts toward the goal of reaching national ambient air quality standards, rather than to allow new pollution sources to be developed.[251]

In late 1981, after considering several approaches to resolving the conflicting goals of the Clean Air Act and PURPA/AB 524, the California Legislature enacted legislation premised on the fact that cogenerated electricity not only displaces utility-created power, but also displaces utility-generated pollution. To benefit the cogeneration facility with the value of such pollution displacement, the bill provided cogeneration projects with "utility offset credits," to be balanced against the emission reductions due to cogenerating electricity. The credits were not to be used to offset emissions due to supplemental firing at the cogeneration facility.[252] To coordinate with AB 524, the new legislation divided projects into those smaller or larger than 50 Mw, and set forth the following provisions:

a. For projects of all sizes, install the appropriate degree of pollution control technology as required by local district rules.
b. For projects of all sizes, provide offsets only for those emissions from the electrical generation portion (cogeneration definition) of the project that exceed the calculated average of emissions from hydrocarbon combustion based electrical generating facilities operated by the serving utility in

248. *Id.*
249. *Id.*
250. *Id.*
251. *Id.* at 8.
252. *Id.* at 10.

the same air basin to provide the same amount of electrical energy.

c. For projects smaller than 50 Mw, provide available offsets to cover offset requirements from the supplemental fuel (process) use and left over cogeneration caused emissions, only from its facilities in the same district. The district must provide for any remaining required offsets.

d. For projects 50 Mw or larger, after consideration of the utility offset credits for the cogeneration portion of the project, provide all remaining offsets as required by district rules for excess cogeneration portion and process caused emissions.[253]

In 1983, the ARB and the California Air Pollution Control Officers Association (CAPCOA) combined forces to find a way to implement AB 1862 without violating the Clean Air Act. CAPCOA members were not pleased with AB 1862 because it encouraged the development of new pollution sources in non-attainment areas. Cogeneration had been billed as electrical generation from waste heat in existing industrial sites, thus increasing industrial activity and electrical generation with little or no new emissions. Instead, most projects were new sources owned by "third-party companies" with no existing facilities of their own from which to obtain emission reductions to offset the cogeneration project emissions.[254] Further, the non-attainment districts had yet to find a way to provide offsets for the projects under 50 Mw, as they were required to do under AB 524. Finally, EPA Region IX had notified California that the "utility emission displacement credits" provided by AB 1862 did not meet EPA requirements that displacements be permanent, quantifiable and federally enforceable.[255]

The dissatisfaction of CAPCOA members from non-attainment districts and the EPA ruling led to yet another flurry of activity. In May 1984, a committee of regulators and industry representatives issued the following recommendations:

253. *Id.* at 11-12.

254. A third-party company builds a cogeneration plant and sells thermal energy to industry and electricity to utilities. The emissions from the third-party company are offset, under AB 1862, by the local air quality district's own efforts. The industrial user of thermal energy can then use its own sites for emission reductions to be used not to offset the cogeneration project, but to offset its own industrial projects, or it could sell its reduction credits to another industrial project. *Id.* at 13-14.

255. *Id.* at 14.

1) The exemption of districts that have not attained, or cannot demonstrate attainment, of the National Ambient Air Quality Standards by the statutory deadline from providing offsets to cogenerators.
2) Develop for EPA approval use of utility offset credit as a control strategy in the districts' Air Quality Management Plans.
3) Use utility offset credits after those offsets provided by the applicant, rather than before as under current law.
4) Require projects to meet all federal requirements.
5) Require thermal energy beneficiaries to provide displaced emissions as offsets.[256]

These recommendations were incorporated into yet another legislative effort, but the bill died in the Senate Committee on Energy and Public Utilities.[257] In 1985, however, some of the provisions were adopted. As it now stands, any district which lacks attainment of National Ambient Air Quality Standards for ozone or nitrogen is not required to provide growth allowances to cogeneration or resource recovery projects until two years after attainment is achieved.[258] Utility displacement credits are calculated on the basis of the amount of utility emissions that would be eliminated by cogeneration.[259] These offsets may be applied only after other already existing offsets—such as from other facilities owned or operated by the same applicant or from other equipment shut down by the new facility are applied.[260] Additional emission offsets are not required of projects producing less than 50 megawatts of electricity (80 megawatts if a project processes municipal waste); that use the appropriate degree of pollution control technology; and that the owner surrenders all available emission offsets including those of thermal beneficiaries from replaced equipment.[261] Although the California program addresses some of the concerns, the confusion between federal requirements and state incentives remains.

As the California effort demonstrates, accommodating new energy sources within the confines of the Clean Air Act can pose a significant obstacle to some states, particularly those states with significant air pollution problems due to urban density or industrial activity. While state efforts may be useful, a more compre-

256. *Id.* at 14-15.
257. Interview with Senator Ayala, California State Legislature (May 31, 1985).
258. CAL. HEALTH & SAFETY CODE § 41604(c) (West Supp. 1985).
259. *Id.* at § 41605(a).
260. *Id.* at § 41605(d).
261. *Id.* at § 42314.

hensive, federal effort to reconcile the conflicting goal of PURPA and the Clean Air Act is needed. Meanwhile, the California legislation can serve as one model for state legislative action in other areas of the country experiencing significant air pollution problems.

V. CONCLUSION

In light of the public utilities' resistance to cogeneration in most of the country, it is economic and regulatory disincentives that are the most significant deterrent to real growth in cogenerated power. Cogeneration often requires custom-built, high-pressure boilers, requiring capital investments that are unlikely to be favored in times of high interest rates and recession. Further, when energy costs are a relatively small proportion of a firm's expenses, the payback period for cogenerated power may be too lengthy. In addition, firms lacking experience in cogeneration see it as an unfamiliar business venture necessarily entailing higher risks. Finally, if capacity credits are tied to long term contracts, firms must have a strong grasp of their long-term energy needs in order to guarantee a certain amount of surplus power. Without active interest and promotion by the utilities, these economic disincentives become significant deterrents. Even in the absence of economic disincentives, confusion concerning problems of compliance with the Clean Air Act, state authority to set purchase rates in excess of full avoided costs, and state authority to order wheeling of cogenerated power from one utility to another can significantly slow development of cogeneration facilities, as potential developers wait to see exactly what their regulatory burden will be.

The two factors that most encourage cogeneration are an active state commission, such as in California, or an ancillary benefit to the utilities. The California experience has demonstrated that mandatory cooperation with QFs, as a precondition to approval for further expansion of traditional, fossil-fuel burning capital plants, may be needed to force public utilities to cooperate with cogenerators. An example of an ancillary benefit is the ability to combine cogeneration with an already necessary process, such as incineration of waste materials. Environmental and disposal regulations that increase the cost of waste disposal act to encourage incineration, where such burning does not violate air pollution standards.

To further PURPA as a means of encouraging cogeneration, the most promising approach is to help state commissions to become active promoters, such as is the case in California. Measures at the federal level could assist states to follow California's lead. For example:

> 1) State Commissions would benefit from further FERC guidance concerning the calculation of avoided costs.
> 2) State Commissions could be encouraged to offer standard purchase rates to large (over 100 Kw) as well as to the small cogenerators. This can be done by FERC guidelines, by regulation or by amending PURPA.
> 3) The Federal Power Act could be amended to loosen the criteria for FERC-ordered wheeling, in order to maximize QF access to transmission lines. State authority to order wheeling should also be clarified.
> 4) Either PURPA or state law could be amended to require more significant utility cooperation with QFs or investment in cogeneration or renewable resource facilities as a precondition to further expansion of fossil-fuel burning plants.
> 5) PURPA could be amended to cover qualifying facilities in which utilities have a controlling interest. By requiring utilities to set standard rates applicable to all QFs, including their own cogeneration facilities, utilities might be motivated to set true avoided cost rates.
> 6) The GAO's recommendation to create a cogeneration office within DOE could forestall future conflicts among regulatory policies, such as the one between FUA and PURPA that had discouraged gas-burning cogeneration.

Overall, rather minor amendments to PURPA can accomplish these limited goals, and ameliorate the economic disincentives to cogeneration that require legislative action for their solution. If amendment of PURPA is undesirable for any reason, model amendments to state utility regulation laws may be in order. Such model amendments could require state commissions to offer standard purchase rates to large cogenerators, and to choose a uniform calculation of avoided and capacity costs. Restrictions on utility ownership of qualifying cogeneration facilities must be eased by federal legislation, however, because PURPA supersedes state law with respect to this requirement. Furthermore, such legislation will require very detailed policy analysis if it is to avoid the anticompetitive effects of many forms of utility ownership.

APPENDIX

COGENERATION FACILITIES (NO. FILINGS) AND CAPACITY IN KW

FUEL	FY 1980 NEW	FY 1980 EXISTING	FY 1980 TOTAL	FY 1981 NEW	FY 1981 EXISTING	FY 1981 TOTAL	FY 1982 NEW	FY 1982 EXISTING	FY 1982 TOTAL
Coal	(3) 88,000	(0) —	(3) 88,000	(2) 611,500	(1) 23,000	(3) 634,500	(7) 246,902	(3) 43,989	(9) 290,891
Nat. Gas	(1) 1,000	(3) 145,250	(4) 146,250	(8) 75,589	(2) 11,000	(10) 86,589	(35) 1,010,427	(8) 1,137,800	(43) 2,148,227
Biomass	(1) 400	(1) 86,000	(2) 86,400	(9) 9,325	(3) 49,268	(6) 98,593	(17) 203,785	(6) 217,665	(22) 421,450
Waste	(1) 75,000	(0) —	(1) 75,000	(0) —	(0) —	(0) —	(2) 74,300	(0) —	(2) 74,300
F06/F02	(1) 23,300	(1) 5,000	(2) 28,300	(0) —	(0) —	(0) —	(3) 15,769	(1) 900	(4) 16,669
Other	(0) —	(1) 19,500	(1) 19,500	(3) 60,280	(0) —	(2) 60,280	(2) 568,800	(1) 3,675	(3) 572,475
Total CF	(7) 187,700	(6) 255,750	(12) 443,450	(17) 796,694	(5) 83,268	(22) 879,962	(66) 2,119,983	(17) 1,404,029	(81) 3,524,012

FUEL	FY 1983 NEW	FY 1983 EXISTING	FY 1983 TOTAL	FY 1984* NEW	FY 1984* EXISTING	FY 1984* TOTAL	TOTAL
Coal	(22) 844,559	(2) 81,000	(23) 925,559	(14) 571,659	(1) 20,000	(14) 591,650	(52) 2,530,600
Nat. Gas	(68) 1,888,913	(8) 267,925	(74) 2,156,838	(79) 1,074,735	(2) 14,910	(81) 1,089,645	(212) 5,627,549
Biomass	(16) 263,639	(6) 122,100	(22) 385,739	(16) 257,172	(6) 119,200	(20) 376,372	(72) 1,368,554
Waste	(2) 228,000	(0) —	(2) 228,000	(2) 67,300	(1) 34,375	(3) 101,675	(8) 478,975
F06/F02	(5) 43,528	(3) 68,600	(7) 112,128	(5) 17,080	(0) —	(5) 17,080	(18) 174,177
Other	(3) 15,450	(0) —	(3) 15,450	(3) 93,000	(4) 99,500	(14) 767,205	
Total CF	(116) 3,284,089	(19) 539,625	(129) 3,823,714	(119) 2,080,937	(11) 194,985	(127) 2,275,922	(371) 17,947,060

* FY 1984 figures are as of July 1, 1984. In January, 1985, the FERC changed to annual reporting. As of January, 1986, the July, 1984 figures are the most recent.