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I. INTRODUCTION

Three key policy problems currently exist which impede the United States in its shift to long-range planning for energy resources and alternatives.[1] First, present conceptualizations of energy scarcity and availability which are based on conventional economic planning responses need to be diversified. The conventional perspectives used are designed to meet emerging needs with either an immediate, expedient response or limited five to ten year goals, using measures of pricing mechanisms, market constraints, economic valuations, and regulatory procedures. Our dependence today on oil as a major fuel is an example of an earlier short-term planning perspective having later consequential effects. The serious examination of long-term problems and prospects of the type of growth intended is limited when the assessment of energy resources is made using only the parameters identified above.

Second, policies for energy resource development must be based on more than mere definitions of the self-sufficiency needed to maintain existing growth patterns in the United States. Conceptual honesty is required for estimates of reserves which will expand with wider exploration, technological improvements in extraction, and changes in demands. The focus must be on measuring the adequacy of resource supply and physical scarcity and using reliable and available data. In what ways and amounts is the United States wholly dependent on imports for any material resources, fuel or nonfuel, for its growth?[2] Do

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1. McHale, *Resource Availability and Growth*, 16 SOCIETY 78-9, 83 (March/April, 1979). McHale contains a definitive examination of various conceptualizations for assessing human, material and energy resources for long-term anticipatory planning.

2. CONGRESSIONAL RESEARCH SERVICE, NATIONAL FUEL AND ENERGY POLICY STUDY, pursuant to S. RES. No. 45, 93rd CONG., 1st SESS. 1-30 (Comm. Print 1973) (summarizing energy conservation and development recommendations in the Final Report of the National Commission

our policies deal in constructive ways with the problems of economic availability of an energy resource? Can the present planning concepts of fiscal economy for resource development be diversified to admit and include the hidden costs—environmental and social—in realistic ways?[3]

Third, growth policies are needed which emphasize regenerative materials, resource systems, and more efficient performance per energy resource unit used. While energy forecasting is not an exact science, estimates that world primary[4] energy demand will double by the year 2000 to 2010 are considered reasonable.[5] The United States will need new and secure sources of energy at that time.

Present arguments for energy growth policy for the United States assume the extremes of a continuum. The "hard" view claims that the technology exists to develop current energy resources, but for a highly centralized electric energy future. By the time fossil fuels become economically unavailable in the United States, it is argued, our electricity supply will be based on coal and nuclear power breeder reactors or fusion, which will be sufficiently developed to meet increased energy needs.[6] The "soft" argument contends that nature places realistic limits on growth and that conservation and efficiency can save large amounts of energy. Moreover, technologies already exist, or are being developed, which can extend the use of existing fossil fuels. District heating, total energy systems, and cogeneration of power from a single fuel resource are examples of known and possible technologies. This type of growth policy, it is contended, is the most rational for the United States

on Materials Policy (June 1973)). An assessment in 1973 of the United States' reserves in seventy nonfuel and fuel resources (including uranium and petroleum) identified only six resources, antimony, asbestos, chromium, flouride, mercury and mica as insufficient in terms of potential domestic supplies. (Twelve resources were not estimated because data were insufficient to do so). In instances where the United States might be wholly dependent on import of materials for supply, none of these materials were critically scarce in world supply. The outlook for industrial materials, therefore, does not appear to be a critical growth factor for the United States except where it may influence balance of payments or force an increase in the rate of domestic exploitation with other resultant energy and environmental costs. *Id.*

3. McHale, *Resource Availability and Growth*, 16 SOCIETY 78-83 (March/April 1979).

4. *Primary* energy is the energy content of fuels before they are processed and converted. Demand projections also distinguish *delivered* energy, that is, usable forms of heating oil, gasoline, or electricity. *See* MASS. INST. OF TECH., ENERGY: GLOBAL PROSPECTS 1985-2000, 23, 49-78 (1977).

5. COUNCIL ON ENVIRONMENTAL QUALITY (CEQ), ENVIRONMENTAL QUALITY, EIGHTH ANNUAL REPORT 273-86 (1977) [hereinafter cited as CEQ, ENVIRONMENTAL QUALITY].

6. *Id.* at 273. See INSTITUTE FOR ENERGY ANALYSIS OF OAK RIDGE ASSOCIATED UNIVERSITIES, AN ACCEPTABLE FUTURE NUCLEAR ENERGY SYSTEM (1976) for a discussion of the concerns of proponents of nuclear power and arguments for a "hard" view.

to pursue.[7]

In the past, such rational growth policy concerns were often ignored. As long as energy in the United States was cheap, there was little incentive for policies or planning for thermal efficiency. Heat waste was cheaper than any scheme to remedy waste. The increasing cost of fuel has led to a reawakening of interest in such technologies as cogeneration to extend the usable power derived from a single resource.[8]

Cogeneration of power from a single fuel source is an example of an available and economically favorable energy conservation practice concerned with the thermally efficient use of an energy resource.[9] In general, cogeneration techniques utilize the heat rejected from the power generating process of the hot effluents usually discharged into the environment to create additional energy.[10] Cogeneration of electricity from industrial process steam and cogeneration of steam from electricity exhaust are the two types of cogeneration in most frequent use in the United States.[11] While the technology is not new, its use and future development may occur in new ways. The concept of cogeneration is presently found in planning for biomass waste fuels development, community integrated energy systems, the dispersion of electrical generation facilities, and solid waste disposal plants.[12] In the United States, cogeneration facilities are statutorily defined in terms of promoting electric utility conservation.[13] Any realistic policies based on thermal efficiency performance of our energy resources will need to accommodate this present statutory preference for utility conservation.

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7. A. LOVENS & J. PRICE, NON-NUCLEAR FUTURES: THE CASE FOR AN ETHICAL ENERGY STRATEGY (1975).

8. *See* H.R. REP. No. 543, 95th CONG., 2d SESS. 5-10, *reprinted in* 6 U.S. CODE CONG. & AD. NEWS, 7674-79 (1978); COMP. GEN. REPORT TO CONGRESS ON AN EVALUATION OF THE NATIONAL ENERGY PLAN, 3-25 (1977).

9. *See* Thermo Electron Corp., I Assessment of Technologies for Research, Development, and Demonstration of Industrial Cogeneration and Waste Heat Recovery in the Near Term 1-3, 1-4 (1977) (Final Report No. TE 4214-75-77 for the Dept. of Energy (DOE) under Contract No. E(11-1)-2866) [hereinafter cited as Thermo Electron Corp., Assessment of Technologies].

10. *Id.*

11. CEQ, ENVIRONMENTAL QUALITY, *supra* note 5, at 272; *See* Sherry, *Energy Interchanges Between Cogenerator and Utilities*, 102:13 PUBLIC UTILITIES FORTNIGHTLY 14, 17-20 (1978) [hereinafter cited as Sherry, *Energy Interchanges*]. Sherry also includes figures which depict power production without cogeneration and with types of possible cogeneration.

12. Address by Gerald Leighton, Integrated Community Energy Systems, Energy Res. & Dev. Admin. (ERDA), Conference on Cogeneration and Integrated Energy/Utility Systems, 2-14, held in Washington, D.C. (June 3, 1977). [All conference addresses hereinafter cited as ERDA Conference].

13. Public Utility Regulatory Policies Act of 1978 (PURPA), § 201, 16 U.S.C. § 796 (Supp. II 1978).

The purpose of this article is threefold: first, to examine cogeneration as a potentially effective technology for more efficient energy performance; second, to assess the most frequently cited economic and legal incentives and disincentives for its development; and third, to explore institutional capacity for change or innovation in relation to cogeneration development. Preliminary facts about the technology itself are discussed first.

II. COGENERATION TECHNOLOGY

Cogeneration can be broadly defined as the simultaneous production of electricity or shaft horsepower and any *useful* thermal energy.[14] The definition and potential for cogeneration may be expanded when the energy sources used include such low-grade fuels as industrial off-gases, liquid wastes, residues from paper and other forest product production, municipal wastes, or sources with a negative energy content such as liquified natural gas.[15]

The advantages of cogeneration in power production are well known. While a utility powerplant requires about ten thousand higher heating value (HHV) British thermal units (Btu) to produce one kilowatt-hour of electricity, a well-balanced cogenerator requires only five thousand or less HHV Btu to produce one kilowatt-hour.[16] Cogenerators operate at a sixty-five to eighty-five percent efficiency level compared to thirty-five percent for straight power producers who lose part of the fuel use through thermal escape.[17] An industrial plant, for example, which requires 250,000 pounds per hour of steam for its industrial or manufacturing process can also cogenerate from ten to thirty megawatts of electricity from the steam, depending on the temperature and the process steam pressure level.[18] Cogeneration could potentially save a good portion of the fourteen quadrillion Btu of waste heat dissipated in the United States each year in electric power generation.[19] This is

14. Sherry, *Energy Interchanges, supra* note 11, at 17.

15. *Id.*

16. *Id.* at 15. In the English system of measures, a Btu is the measuring unit for energy. One Btu is the amount of energy necessary to raise the temperature of one pound of water by one degree Fahrenheit from 39.2 to 40.2 degrees Fahrenheit. D. KASH, M. DEVINE, J. FREIM, M. GULLILAND, R. RYCROFT & T. WILBANKS, OUR ENERGY FUTURE 473 (1976).

17. *Sherry, Energy Interchanges, supra* note 11, at 15.

18. *Id.*

19. Thermo Electron Corp., A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries, 2-1, 2-2 (1976) (Rep. No. TE 5429-97-76, Final Report to FEA under Contract No. 0-04-50224-00) [hereinafter cited as Thermo Electron Corp., Inplant Generation in Industries].

the equivalent of more than two million barrels of oil per day.[20]

Other industrialized countries, particularly Germany and Japan, generate considerably more industrial inplant cogeneration than the United States. The cost-effectiveness of the technology has led West Germany to cogenerate about twenty-eight percent of its electricity needs.[21] In the 1960s about seventeen percent of the United States' electricity was produced through cogeneration, while during the 1970s the percentage decreased to less than five.[22] The change is attributed primarily to the long-term trend of cheap public utility electricity being available for industrial use and growth in the United States.[23] With the incentive of cheap electricity, capital expenditures for cogeneration steam and power equipment are uneconomical for an industry which is developing or expanding. Tax structures make buying electricity (an operating expense) advantageous compared to generation (a capital expenditure). Shorter work weeks in industrial plants and management attitudes about operating power facilities have also been factors in the decline of early industrial cogeneration.[24] Few incentives to increase industrial cogeneration in the United States have existed as long as bulk industrial electricity was cheap.[25]

Cogeneration by industrial firms to provide their facilities with energy also results in competition with the regulated utilities which supply industrial customers with electricity, steam, substitute natural gas, or low heating value gas.[26] In 1975 utilities supplied over eighty-eight percent of the national average of the industrial power requirements in the United States.[27] Some industries, such as meat packing, rely totally on utilities. A few industries generate a fraction of their own power, while the pulp and paper industry generates about fifty percent of its power requirements.[28]

The fuel conserving advantages of cogeneration have long been

20. *Id.* at 2-2.
21. White & Green, *Cogeneration in West Germany*, 197 SCIENCE 618 (1977).
22. Address by Senator Gary Hart, Cogeneration-Energy Conservation Measure for Today, ERDA Conference, *supra* note 12, at 4.
23. S. REP. No. 361, 95th CONG., 2d SESS., *reprinted in* 6 U.S. CODE CONG. & AD. NEWS 8179 (1978).
24. *Id.*
25. CEQ, ENVIRONMENTAL QUALITY, *supra* note 5, at 283.
26. Sherry, *Energy Interchanges, supra* note 11, at 14.
27. Rep. No. 192, ENERGY USERS REPORT (BNA) (April 14, 1977) (cited in Thermo Electron Corp., Assessment of Technologies, *supra* note 9, at 1-3).
28. Thermo Electron Corp., Summary Assessment of Electricity Cogeneration in Industry 1-3, 1-4 (July, 1977) (Rep. No. TE 4214-75-77 to the Div. of Industrial Energy Conservation, DOE, under Contract No. E(11-1)-2866).

recognized. However, an industry's management decision on expenditures for cogeneration equipment is made on the basis of the risk on the rate of return for the equipment as well as the perceived compounded risks of return because of the specific technology and market of the particular industry.[29] The investment risk appears especially disparate to industrial management when compared to the same decision made by utilities to invest in cogeneration equipment. Industry must compete in an arena where technologies and markets change rapidly, while utility powerplants are built with low-business risk to service technological changes over time in a diverse but stable market.[30] The resurgent nonutility interest in cogeneration, therefore, arises more from the practical need of industry to find alternative boiler fuels and cheaper electric energy because of increased costs for fuel and utility power[31] than from the issue of the rate of return on investments.

A cogeneration facility is defined in the federal legislation of the National Energy Act (NEA) of 1978[32] as a facility which produces: "(i) electric energy, and (ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes."[33] The definition can include what are known as "topping" and "bottoming" cycles. The "topping" cycle is cogeneration wherein fuel is initially consumed to produce electricity and the moderate temperature exhaust heat is delivered for an industry's process steam or heat requirements.[34] Industrial firms, however, are more interested in the reverse of the sequence, that is, the "bottoming cycle" wherein fuel is consumed to produce high temperature industrial process heat or steam

29. Sherry, *Energy Interchanges, supra* note 11, at 16.

30. *Id.* Utilities, however, will make incremental investments in new facilities that yield only eight percent in assets while energy users will turn down investments in conservation equipment yielding an equivalent amount of electricity if the annual return from the expenditure falls below thirty percent. Halsopoulos, Gyftopoulos, Sant & Widmer, *Capital Investment to Save Energy,* HARV. BUS. REV. 113 (March-April, 1978).

31. *Idea of Producing Own Power Intrigues Many Companies; Utilities are Alarmed,* Wall Street J., Mar. 1, 1979, at 40, Col. 1 [hereinafter cited as *Producing Own Power*].

32. National Energy Act of 1978, comprised of Pub. L. No. 95-617 (codified in scattered sections of 15, 16, 30, 42, 43 U.S.C.A. (West Supp. 1979)), Pub. L. No. 95-618 (codified in scattered sections of 19, 26, U.S.C.A. (West Supp. 1979)), Pub. L. No. 95-619 (codified in scattered sections of 12, 15, 42 U.S.C.A. (West Supp. 1979)), Pub. L. No. 95-620 (codified in scattered sections of 15, 19, 42, 45, 49 U.S.C.A. (West Supp. 1979)), and Pub. L. No. 95-621 (codified in scattered sections of 15, 42, U.S.C.A. (West Supp. 1979)).

33. PURPA, § 201, 16 U.S.C. § 796(18)(A)(i-ii) (Supp. II 1978).

34. Address by Douglas Harvey, Industrial Cogeneration, ERDA Conference, *supra* note 12, at 10-11. For definitive cycle descriptions and cogeneration systems by percentages of efficiency and exhaust heat, and potential fuel savings for three types of industry see Thermo Electron Corp., Inplant Generation in Industries, *supra* note 19, at 3-1 to 3-30.

and the moderate temperature exhaust is used to produce electricity.[35]

Cogeneration methods can provide energy efficiency for other than large industrial systems. Small users who use under one thousand kilowatts of electricity can convert to their own cogeneration. Such an operation links a diesel engine to an electric generator and the engine exhaust and hot cooling water are piped to a waste-heat boiler to produce steam.[36] In 1979, an estimated 1500 small user cogenerators were in use in the United States located in schools, shopping centers and hospitals as well as small industries.[37] In a further attempt to encourage energy efficiency in places other than large industry, federal grants have been made available to schools and hospitals for such cogeneration under the National Energy Conservation Policy Act (NECPA) of 1978.[38]

Large cogeneration facilities in use in the United States are generally of two types. One type supplies steam from large central dual-purpose power stations to nearby industrial sites. To make its investment profitable, a utility must find an industrial plant nearby whose steam requirements approximate the utility's large output. The industry should have a regular load schedule and operation and be likely to survive for some time.[39] Economies of scale for a utility in the steam market, however, differ from electricity production. Steam can be transported and sold economically only within a radius of three to five miles. Therefore, a large single user or a concentrated group of diverse users must be nearby. Backup steam supply grids for standby or back-up problems that plague an electrical power supply grid would not be present. Engineering variations in delivery of steam supply will occur, moreover, because of pressure, corrosion, and condensate return.[40]

For all of these reasons, the production of electricity by utilities and steam production by industry are more likely occurrences and make economic sense. However, utilities can operate a viable dual-purpose powerplant (one which sells steam to industry and produces

35. Address by Douglas Harvey, Industrial Cogeneration, ERDA Conference, *supra* note 12, at 11. The final regulations promulgated by FERC distinguish efficiency standards for topping and bottoming cycles of cogeneration facilities by type of primary energy source. FERC Qualifying Requirements for Cogeneration Facilities, 40 Fed. Reg. 38,876 (1979) (to be codified in 18 C.F.R. § 292.206 (1980)).

36. *Producing Own Power, supra* note 31, at col. 1.

37. *Id.* at col. 2.

38. National Energy Conservation Policy Act of 1978 (NECPA), § 302(a), 42 U.S.C.A. § 6371(2)(K) (Supp. II 1978).

39. CEQ, ENVIRONMENTAL QUALITY, *supra* note 5, at 272.

40. Sherry, *Energy Interchanges, supra* note 11, at 15.

electricity for the grid) if the facility is built on a sufficiently large scale with a diverse group of long-term contract customers to limit the utilities' risks. While the dual-purpose powerplant is not common, it is found more frequently than arrangements of industry selling by-product power to a utility.[41] A new dual-purpose power station would probably be best implemented by locating the facility near an existing industrial site. As stated earlier, long steamlines are very expensive and industry must be fairly close to make the operation of a dual-purpose powerplant economically feasible.[42]

These latter types of cogeneration with potential for excess power are viewed as providing savings in fuel consumption as well as reducing future capital construction costs for new electricity generation. The result should mean reduced capital costs for the nation, lower external financial demands for utilities, and lower electric rates for customers.[43]

The second type of cogeneration facility used in the United States is the smaller scale generation of industrial steam and electrical power produced from small decentralized powerplants at the industrial site. The steam and all or nearly all of the electricity are used directly at the plants with leftover electricity supplied to the utility grid.[44] In addition to these two types of facilities, an estimated five hundred industrial plants in the United States are equipped for generating ten thousand or more kilowatts for their own use.[45]

Three industries, paper and pulp, chemical, and oil refining commonly use the self-sufficient, small-scale by-product cogeneration described above for their steam process needs. Much of the data and evaluation of the feasibility and future of industrial by-product cogeneration in the United States comes from recent studies of inplant generation made for these particular industries.[46] Data showing energy efficiency indicate that a central station steam plant is, at most, about thirty eight percent efficient because of thermal discharge. In contrast,

41. Dow Chemical Co., Energy Industrial Center Study 100-01 (June, 1975) (Report No. 750012 to Office of Energy R & D Policy, National Science Foundation (NSF)) [hereinafter cited as Dow Chemical Co., Industrial Center Study].

42. *Id.* at 114.

43. Dow Chemical Co., Energy Industrial Center Study: Executive Committee Summary Report and Policy Proposals 9 (June, 1975) (prepared for the Office of Energy R & D Policy, NSF under grant DEP74-20242) [hereinafter cited as Dow Chemical Co., Executive Summary].

44. CEQ, ENVIRONMENTAL QUALITY, *supra* note 5, at 283.

45. *Producing Own Power, supra* note 31, at col. 2.

46. For a comprehensive evaluation of the economies of inplant power generation in these specific industries, weighing technical and nontechnical barriers and the national impact of increased generation, see Thermo Electron Corp., Inplant Generation in Industries, *supra* note 19.

an industrial powerplant can be sixty to seventy-five percent energy efficient by using thermal exhaust for self-sufficient cogeneration purposes.[47]

The electric utilities, in general, have opposed industrial generation of electric power and tend to establish rate schedules and rules that hinder potential cogeneration. For example, utilities have often required higher minimums, prices, and ratchets[48] of industries that produce part of their own power. Backup and supplementary power have often been priced high and surplus and export power purchased at low prices when cogenerating industries want to sell excess power to the utility grid.[49] Section 210 of the Public Utilities Regulatory Policy Act (PURPA) attempts to correct some of these hindrances by requiring utilities to sell and purchase excess power from qualifying cogeneration facilities at rates which are "just and reasonable" to the electricity consumers of the utility and in the public interest.[50] The legal issues relating to improved efficiency in the use of all fuel resources in the United States may well be defined in terms of the more narrow legal issues arising from the cogeneration of electric power and industrial steam. The present economic and legal incentives for the development of cogeneration are assessed in the material which follow.

III. Incentives in the Development of Cogeneration

The conservation of energy is the cornerstone of the Carter administration's national energy policy.[51] The United States' Energy Research and Development Administration (ERDA) has defined three methods, "curtailment," "energy efficiency," and "fuel switching," for

47. Address by William Barrett, Cogeneration - Ventures: Regulatory Issues, ABA National Institute, Industrial Energy Choices and Regulation 2, held in New Orleans (September 21-22, 1978) [hereinafter cited as Barrett, Cogeneration - Ventures]; Thermo Electron Corp., Inplant Generation in Industries, *supra* note 19, at 1-1.

48. The ratchet rate is a device used for recovering demand related costs. In general, the ratchet rate form has the effect of encouraging customers to have level annual loads or high individual load factors since their monthly bills are based in part on their prior use. Electric Power Research Institute, Electric Utility Rate Design Study, Reference Manual and Procedures for Implementing PURPA 1.143, 6 (February, 1979).

49. Sherry, *Energy Interchanges, supra* note 11, at 16.

50. PURPA, § 210, 16 U.S.C. 824a-3(b)(1) (Supp. II 1978).

51. The President's Address Delivered Before a Joint Session of the Congress, 13 WEEKLY COMP. PRES. DOC. 566 (April 20, 1977); *Energy Conservation Provisions of President Carter's Energy Program: Hearings on Parts A, B, C, and G of S. 1469 Before the Subcomm. on Energy Conservation and Natural Resources*, 95th CONG., 1st SESS. (May 3, 1977).

viewing conservation policy.[52] Long-term ERDA goals include using technology to incorporate energy saving features into all production, community energy systems, and energy processes used daily.[53] Congress included several specific energy conservation techniques throughout the programs of the NEA.[54]

A. *Present Cogeneration Legislation*

Legislation which could encourage additional cogeneration in the United States is present in several provisions of the NEA of 1978. The existing ten percent investment tax credit would be applied for the purchase of "alternative energy property" which could be defined as cogeneration equipment.[55] Industries using cogeneration would be entitled to inter-tie with utilities' transmission facilities to buy and sell power.[56] The Federal Energy Regulatory Commission (FERC) must establish procedures to assure that rates for the sale and purchase of electric power between cogenerators and utility companies are "just and reasonable" and do not discriminate against the cogenerators.[57] Cogeneration facilities which do not sell at least half of their electricity are permanently removed from the category of "powerplant" and, therefore, from the gas limitation use and the 1990 cut-off provisions applicable to existing powerplants.[58] FERC is empowered under PURPA to abrogate state organizational and financial jurisdiction over cogenerators. The Secretary of Energy may exempt "qualifying cogenerator facilities" from regulation by state and federal regulations and laws if he deems such regulation unnecessary.[59] In addition, the Secretary may prescribe rules which may exempt cogenerators in whole or in part from the Federal Power Act (FPA) and the Public Utility Holding Company Act (PUHCA) of 1935.[60] The final rules promul-

52. Address of Dr. Maxine Savitz, Introduction and Overview, ERDA Conference, *supra* note 12, at 1-2.
53. *Id.* at 2.
54. *See, e.g.*, PURPA of 1978, §§ 202, 203, 205, 210, 16 U.S.C. §§ 824, 824a, 824a-1 - 824a-3 (Supp. II 1978); § 605, 15 U.S.C. § 717 (Supp. II 1978); Energy Tax Act of 1978 (ETA) § 301, 26 U.S.C. § 46 (Supp. II 1978); NECPA, § 210, 42 U.S.C.A. § 8211 (Supp. II 1978); § 301, 42 U.S.C. § 6371 (Supp. II 1978); Powerplant and Industrial Fuel Use Act of 1978 (PUA), §§ 201, 202, 42 U.S.C. §§ 8311-8312 (Supp. II 1978); Natural Gas Policy Act of 1978 (NGPA), §§ 401-04, 15 U.S.C. §§ 3391-3394 (Supp. II 1978).
55. ETA of 1978, § 301(b)(2)(A)(i), 26 U.S.C. § 38(1) (Supp. II 1978).
56. PURPA of 1978, § 210(A)(1) and (2), 16 U.S.C. § 824a-3 (Supp. II 1978).
57. NECPA of 1978, § 302(a), 42 U.S.C. § 6371(2)(K) (Supp. II 1978).
58. PUA of 1978, § 212(c), 42 U.S.C. §§ 8321-24 (Supp. II 1978).
59. PURPA at § 210(e), 16 U.S.C. § 824a-3 (Supp. II 1978).
60. *Id.*

gated by FERC in March of 1980 provide these exemptions.[61]

The Comptroller General's 1977 report to Congress, evaluating the President's National Energy Plan, submitted that additional industrial cogeneration would be a means of saving energy by reducing the quantities of heat currently being wasted.[62] The report pointed out that the constraints which had inhibited the development of industrial cogeneration, such as declining block rates[63] offered to industry by utilities and utility reluctance to provide the steady backup or supplemental service needed by a cogenerator, were removed by the provisions of the NEA.[64] The report also pointed out that provisions in the Powerplant and Industrial Fuel Use Act (PUA) exempting industries which purchased cogeneration equipment from requirements to convert to non-oil and gas fuels were counter to the major thrust of the administration's policy to conserve energy by switching industry from gas and oil to coal.[65]

B. *Economic Incentives*

Any discussion of the economic incentives of cogeneration needs to be prefaced with the caution that only generalized statements are valid at this time. Many of the economic determinations for financing and pricing of the mandatory purchase of power, as well as savings in internal energy costs for the cogenerator, will turn on the implementation by the states of the final regulations written by FERC for sections 201 and 210 of PURPA.[66]

61. Exemption of qualifying facilities from the Federal Power Act, 18 C.F.R. § 292.601 (1980); Exemption of qualifying facilities from the Public Utility Holding Company Act and certain state law and regulation, 18 C.F.R. § 292.602 (1980).

62. Comp. Gen., Report to Congress on an Evaluation of the National Energy Plan 3.26 (July 25, 1977).

63. A declining block rate provides electric service to a class of electric consumers at a decreased charge by the utility as kilowatt hour consumption increases during any period: The costs to the utility attributable to that energy do not necessarily decrease. PURPA at § 111(d)(2), 16 U.S.C. § 2621(d)(2) (Supp. II 1978).

64. Comp. Gen., Report to Congress on an Evaluation of the National Energy Plan 3.26 (July 25 1977). PURPA *requires* electric utilities to offer to sell electric energy to qualifying cogeneration facilities. PURPA at § 210, 16 U.S.C. § 824a-3 (Supp. II 1978).

65. Comp. Gen., Report to Congress on an Evaluation of the National Energy Plan 3.26 (July 25, 1977). PUA, § 212(c), 42 U.S.C.A. §§ 8321-24 (Supp. II 1978) allows the Secretary to grant a permanent exemption if he finds the cogeneration facility has demonstrated economic and other benefits of cogeneration are unobtainable unless either petroleum or natural gas or both are used in the facility. *See also* 10 C.F.R. § 505.27 (1979).

66. Small Power Production and Cogeneration Facilities: Regulations Implementing § 201 and § 210 of PURPA, 45 Fed. Reg. 12,233, 12,234 (February 25, 1980) (to be codified in 18 C.F.R. § 292.301 *et seq.*).

Perhaps economic disincentives should exist which would discourage utilities from building unnecessary powerplants where cogenerated power is available. However, the discussion of economic disincentives and incentives in this section of the article is limited to the perspective of the potential industrial inplant power and generator of cogeneration. Technological concerns for optimizing economies of design of particular technologies or developing new economical combustion techniques are not discussed herein.[67]

1. Development

The development of industrial inplant generation may be limited initially by technical and operational decisions beyond the scope of this article.[68] Social, political, institutional, and legal barriers exist and create economic disincentives. However, the regulatory issues and public utility attitudes toward industrial cogeneration seem to be the most troublesome limitations for potential cogenerators to overcome.

The development of industrial cogeneration can be assessed, on the whole, as a significant strategy for conservation of fuel. When industrial electricity can be generated more cheaply than central station power and industrial excess power is available for sale, future electricity cost savings are possible. Utility power customers, other than industrial customers, are protected by a slower rate of growth in new utility

67. *See* Thermo Electron Corp., Assessment of Technologies, *supra* note 9. This report is an assessment of cogeneration technology, the state of the technology, problem areas, and potential near-term use in industrial cogeneration. Heat pumps, combined gas/back-pressure steam turbine cycles with supplementary firing, diesel topping, open cycle gas turbines, small, high-efficiency steam turbines, closed gas turbine Brayton cycle, the Stirling engine, the fuel cell, thermiones energy conversion, and magneto hydrodynamic power generation are examined.

68. Sherry, *Energy Interchanges, supra* note 11, at 17-20, fig. 1-7. Differences can be defined in terms of capacity, type of cycle used, and type of energy produced. Facilities are also typed by ownership: owned and operated by a utility selling steam and electricity to industry; owned and operated by industry, purchasing additional power required after by-product electricity; owned and operated by industry, exporting power to other industry or the utility. Cogeneration production varies by design and need of the industry. Assuming a broad definition of cogeneration, technical designs can include fuel that will be producing sufficient steam to provide process steam and supplementary electricity through boiler and steam turbines, by-product heat and fuel, with fresh fuel providing process steam, electricity and a raw process fluid such as syngas; hot exhaust gas turbines and fresh fuel-producing process steam; hot gas turbines and supplementary fuel producing process steam and chemical or by-product fuel and fresh fuel directly producing shaft horsepower eliminating the intermediate electrical step. *Id.* A study done by the Dayton Power and Light Company discusses several of the considerations of plant design, ownership, capital costs, fuel options, economic analysis and financing, rates and tariffs, prices for steam, and legal and regulatory issues. Gibbs and Hill, Inc., A Study for the Dayton Power and Light Company of Cogeneration (May, 1978) (Report No. DPL D-61838 for the Public Utility Commission of Ohio (PUCO)) [hereinafter cited as Gibbs and Hill, Study for DP & L].

generation while an alternative source of electric energy is made available for utility grid use.[69] Utilities, however, often remain negative toward these considerations.[70] Even though economic factors are favorable for utilities to invest in inplant cogeneration, some incentives are probably still necessary to promote substantial investment in cogeneration. Some of the incentives that have been proposed to alter this negative attitude of utilities are an increase in the investment tax credit from ten to twelve and one-half percent, provisions for accelerated write-offs, guaranteed twenty year loans at favorable and contained market interest rates to cover up to ten to fifteen percent of the incremental investment for power, and tax concessions which cover all equipment.[71]

The potential industrial cogenerator needs to find financing arrangements. Even with sound technical and operational reasons for developing cogeneration, he may not be too anxious to enter into these. Project financing techniques are complex and may include leverage leasing arrangements,[72] or new joint venture entities, with companies

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69. Dow Chemical Co., Executive Summary, *supra* note 43, at 1-2. Estimated average annual savings range from two to five billion dollars from 1976 to 1985 in capital requirements for new electric generating and transmission capacity. Dual-purpose central power stations reduce the amount of external financing which electric utilities would have to raise on their own by an estimated three billion a year from 1976 to 1985. Consumer savings attributable to such implementation range from 2.9 to 6.0 percent. Lower rates of return would be acceptable and possible if external capital demands were reduced. *Id.*

70. The utility succeeds by making new investments. When it distributes and markets power produced by an industrial cogenerator, it has fewer investment opportunities. Utility investors do not receive a return merely by the regulated utility buying and selling power with a minimum earning added through investments. *See* Sherry, *Energy Interchanges, supra* note 11, at 16.

71. Thermo Electron Corp., Inplant Generation in Industries, *supra* note 19, at 8-2.

72. Vanderwicken, *The Powerful Logic of the Leasing Boom*, 88 FORTUNE 132-36 (November, 1973).

> When depreciation, interest charges and investment credit related to ownership are only marginally beneficial as a tax write-off for a company, the company may decide to leverage lease the facility. Tax benefits are passed on to the lessor and the lessor can provide the company with a lower than normal rental payment. Under the leveraged lease the lessor has the tax benefits of the facility to shield taxable income and can also concentrate the tax benefits by leveraging the lease. The lessor of the facility, if leveraging the lease, finances a small percentage of the purchase price, with one hundred percent ownership as an asset, and finds long-term creditors who finance the balance. The leveraged lease agreement generally involves the following:
> (1) It meets the definition of a direct financing lease.
> (2) There are three participants in the lease arrangement—(a) An owner-lessor (equity participant), (b) a lessee (user of the asset), and (c) a third party long-term creditor (debt participant).
> (3) The owner-lessor provides a portion of the cost of the property to be leased, generally twenty to fifty percent.
> (4) Long-term creditors (generally financial institutions) provide the remaining portion (fifty to eighty percent) of the cost of the equipment. The amount provided by these third-party creditors is generally called the leveraged debt. The leveraged

and/or a public utility as co-venturers. The joint venture entity will share the responsibility of ownership and development of the facility, as well as the financing.[73] The choice of an appropriate business arrangement for ownership of the inplant facility will depend largely on

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> debt is structured without recourse to the owner-lessor; it is secured by a pledge of lease payments or by a security interest in the property. For this reason, the interest rate obtained by the long-term creditors for the leveraged debt is based, in part, on the lessee's credit rating.
>
> (5) The asset is then purchased from the manufacturer or contractor by the lessor-owner and leased to the lessee. In return, the lessor-owner receives the rental payments, makes debt service payments (principal and interest) to the long-term creditors, and retains any difference. The residual value from the disposition of the asset at the end of the lease term is retained by the lessor. Generally, the lessor's net investment declines during the early years and rises during the later years of the lease. The lessor's return and early net cash inflow results from several sources: (1) lease rentals; (2) investment tax credit; and (3) income tax benefits such as depreciation (often accelerated) on the total cost of the property, interest expense on the debt, and possibly others.

D. KIESO & J. WEYGANDT, INTERMEDIATE ACCOUNTING 845-46 (1977).

73. K. F. Seplow, Financial Aspects of Cogeneration: Obstacles and Opportunities, ERDA Conference, *supra* note 12, at 8 [hereinafter cited as Seplow, Obstacles and Opportunities]. In a Dow Chemical Company study, economic and financial considerations for by-product electric power from industrial steam generation are examined in four assumed generation alternatives for new by-product power generation in 1980. The dual-purpose central power station and a combined implementation of industrial power generation and dual-purpose central power stations are structured to be joint ventures. The ventures can be financed with fifty percent equity from the industry utility partners and fifty percent debt. Equity is contributed by the partners in proportion to what they would have to invest in separate steam and power facilities. (In the coal fired unit example, the utility provides eighty-four percent of equity.) Prices paid by the utility for electricity and the industry for steam are set so each partner saves an amount as compared to what purchase outside the joint venture would be to provide a "standard" return, *i.e.*, twelve percent after tax on equity for the utility, twenty percent before tax on total investment for industry. Dow Chemical Co., Industrial Center Study, *supra* note 41, at 104, 264-69.

In a study for Dayton Power and Light Company of Ohio, the following financial approach is outlined for a joint venture of industrial investors and the utility:

> The joint venture partnership finances the project on the basis of 35% equity and 65% debt with the following conditions:
>
> 1. The ownership of each joint venture partner should be less than 25 percent to be able to keep the debt off the company's books. (The 25% ownership limitation anticipates that the Financial Accounting Standards Board (FASB) may lower the present 50% rule, in the future).
> 2. Long-term debt financing for the project is secured by take-or-pay contracts.* The interest rate on this debt will be based on a composite credit rating of the user group, excluding the utility.
>
> A fundamental assumption is that all tax credits can be used by the joint venture owners as they occur, that is, that the joint venture partners can use interest expenses and the investment tax credit to offset tax liabilities from their other businesses. Tax credits accrue to the joint venture partners on the same pro rata basis in which they share ownerships. If the owners cannot utilize the tax credits or losses in the year in which they are incurred, the price of steam would have to increase in order to yield the same discounted cash flow return, to make up the tax credit loss.
>
> In order to determine the annual revenue requirements, a discounted cash flow (DCF) analysis is performed on the estimated future costs and revenues. The objective is to achieve a specified DCF return on equity (ROE) over the life cycle of a project.
>
> * The take-or-pay contract stipulates a minimum user charge regardless of contract actual amount of steam and electricity use.

local considerations and attitudes and state laws that affect business entity structures.

In co-ownership joint equity investment programs, each participant can avoid accounting for the full debt burden of the ownership by sharing in the management but not controlling it, and thereby protect the individual borrowing capacity of the base industries.[74] The business form of a partnership composed of special purpose subsidiaries of the equity participants provides a form of venture entity which permits full use of current tax benefits of ownership.[75] The form also insulates the investors from the liability and regulation which the venture generates. Limited investment by the participants with agreements concerning the purchase of output and payments of minimum charges allows the venture to attract institutional debt investments.[76] The major drawback to any business investment, however, lies in the fear that the parties will be subject to regulation as a public utility. The exemptions of the parties from regulation under PUHCA will be discussed under regulatory incentives.

2. Capital Investment

The primary concern of an industrial company today is not conservation of energy, but rather what fuel the industry is going to burn in its boilers for the next twenty years. The PUA clearly states that, except as authorized, natural gas or petroleum shall not be used as a primary energy source in a new installation and use may be prohibited in any existing major fuel burning installation after 1990.[77] Permanent exemption from one or more of the prohibitions of the Act is available

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Gibbs & Hill, A Study of DP & L, *supra* note 68, at IV-3 to IV-4.

If the joint venture is that of several industrial companies rather than the utility and industry examples in the paragraphs above, financial considerations will turn on whose credit will support the project. The major process steam user has the lowest credit rating and has an advantage if the joint venture is a credit mix of the ratings of all participants. Barrett, Cogeneration - Ventures, *supra* note 47, at 7.

74. Seplow, Obstacles and Opportunities, *supra* note 73, at 9. If the financial share of the project is in proportion to the steam demand of the participants, the item will be on the balance sheet of at least one company. Changes in accounting practices for industrial companies will probably require a minimum of footnoting the venture on the books and a maximum of consolidating the debt on the balance sheets of all participants. Barrett, Cogeneration - Ventures, *supra* note 47, at 7.

75. Seplow, Obstacles and Opportunities, *supra* note 73, at 9. Consideration needs to be given to how quickly venture parties can utilize the investment tax credit. If it cannot be used immediately, the effect on costs is sizable. Barrett, Cogeneration - Ventures, *supra* note 47, at 7.

76. Seplow, Obstacles and Opportunities, *supra* note 73, at 9.

77. PUA, § 202, 42 U.S.C. § 8312(a) (Supp. II 1978); § 302, 42 U.S.C. § 8342 (Supp. II 1978).

for cogeneration facilities, however.[78] The petitioner must show that economic and other benefits of cogeneration will not be realized if an alternative fuel source, other than oil or gas, is used in the boiler.[79] Rules for the exemption may allow cogeneration where net oil savings are effected or present oil use in the boiler is necessary for the future use of a synthetic fuel.[80]

The long range option, if process steam is required for production, is for an industry to switch from oil or natural gas and convert to coal. Where process steam is required for production there has been a trend over the years for industry to move away from coal boilers toward the use of oil and gas package boilers. These boilers, however, are unsuitable for cogeneration power production. In addition to the technology of the boiler, the economics of industrial cogeneration also favor coal over oil and gas.[81] Since gas-fired boilers cannot be operated on coal, conversion requires a major capital expenditure for a new coal-fired steam plant. If the industry requires about two million pounds per hour of process steam, the steam plant will cost about $200 million to build.[82] Today, the cost of a new coal-fired steam plant can amount to fifty to seventy-five percent of the total capital cost of the facility. The economies of scale increase tremendously, however, with the size of the steam plant.[83] If the industry is located in an industrial complex, the same economies of scale can be realized from a single coal-fired steam plant serving a three mile radius. Such "community" cogeneration plants will reduce the amount of capital investment required of the individual industry.[84]

Mere conversion to a coal-fired steam plant does not mean the new facility is a cogeneration plant. The cogeneration of electricity in a

78. *Id.* at § 312(c), 42 U.S.C. § 8352(c) (Supp. II. 1978).

79. *Id.* at § 312(c), 42 U.S.C. § 8352(a)(1) (Supp. II 1978).

80. *Id.* at § 212(c), 42 U.S.C. § 8322 (Supp. II 1978); § 312(c), 42 U.S.C.A. § 8352 (Supp. II 1979).

81. *See* Dow Chemical Co., Industrial Center Study, *supra* note 41, at 28, 33, 39. On the basis of projected comparative fuel costs (1975), a company with an oil or gas burning package boiler in 1974 could expect to attain a ninety-three percent return on its investment by switching in 1980 to a coal-fired boiler. *Id.* at 49.

82. Barrett, Cogeneration - Ventures, *supra* note 47, at 3.

83. *Id.* Engineering analysis of costs indicates that steam costs can range from $5/1000 pounds to $15/1000 pounds based on the size of the facility. This cost difference can allow an industry to be competitive in the market place. *Id.*

84. *Id.* at 4. Over one hundred and fifty sites called "energy clusters" have been identified as locations in the United States that could support one hundred fifty to one hundred seventy-five coal-fired steam plants. *Id.* at 4.6 (discussing National Science Foundation, Assessment of Energy Parks v. Dispersed Electric Power Generation of Facilities (1975) (prepared for ERDA, DOE)).

steam-only plant requires an additional ten to fifteen percent capital investment in cogeneration equipment.[85] If the industry, by generating its own power instead of buying power from a utility, can obtain annual net savings that amount to twenty percent of the capital cost of the cogeneration equipment, the savings amount can be discounted at that rate of return over a five year payout period to justify the additional capital investment.[86] Management makes an additional analysis, however. As stated previously, steam user requirements for an industry are unique to the industry's own production in a market full of high technological risk. Cogeneration equipment must carry that inherent market risk along with its own investment risk when the company figures any return on the equipment investment.[87] Management decision making tends to restrict capital funds to projects directly related to production and the business.

Some analysts feel industry may look for a higher rate of return on its conservation equipment expenditures than on production investments.[88] In whatever manner the decision is made, a comparison of rates of return over the hurdle rates for new investment in a shared steam plant still positively favors industrial cogeneration even with regulatory constraints.[89] In addition, the shared steam plant can also reduce the amount of capital investment of an individual industry in cogeneration.

Nothwithstanding their advantages, shared steam or "community" plants are not created without effort. Highly competitive industries in an energy cluster must be willing to share accurate information related to production in order to plan steam requirements for twenty to thirty years and competition may prevent the release of necessary data.[90] Other problems also exist. How will the debt financing be shared? Will it be shared in proportion to the steam requirements of the parties? How will the venture and debt be carried on the balance sheets of

85. *Id.* at 4.
86. *See id.*, chart no. 3.
87. Sherry, *Energy Interchanges, supra* note 11, at 16.
88. *See id.* Sherry expresses disagreement with the analysts who have taken this position.
89. Barrett, Cogeneration - Ventures, *supra* note 47, at 4-5. Even in by-product power installations, using a return on investment (ROI) of twenty percent as the criterion of economic viability, and taking into account uncertainties in package boiler costs, one study indicates that individual industrial facilities using more than four hundred thousand pounds per hour of process steam or twenty MW of electrical by-product power generation could achieve costs per kilowatt hours low enough to bring a pre-tax return of twenty percent or better. Dow Chemical Co., Industrial Center Study, *supra* note 41, at 75.
90. Barrett, Cogeneration - Ventures, *supra* note 47, at 4-6.

the separate industries? What are the conflicting financial goals of investment of each of the participants? Energy efficiency investments must always compete with other and often more attractive investments available at the same time to all parties including the participants, lessors, and long-term creditors.

3. Pricing Practices

Industries buying electricity from public utilities today enjoy an average cost pricing system with rates based on the utility's cost of all old and new plants, not just the plant which may serve that industry.[91] Large industries obtain declining block rates as utility customers, paying less per kilowatt than smaller users.[92] Industrial companies have sound economic incentives for continuing with such advantageous arrangements. One such incentive is that, in addition to the favorable electric power rates, industry is often able to burn natural gas (for its steam production) at a regulated cost below that of such environmentally costly fuels as oil or coal. If the plant's steam to power ratio is high enough, it may be energy efficient for a cogenerator plant to export power for purchase. An industry's decision to cogenerate will include this factor as well as other economic incentives.

The purchase level of the export power, however, if set at the same level as the utility equivalent power, encourages purchase of the exported power and may help reduce national fuel use, but the price does not benefit the utility and its other present customers. PURPA states that the purchase rate shall not exceed the incremental cost to the electric utility of alternative electric energy.[93] While a broad range of pricing mechanisms and arrangements for purchase of cogeneration power

91. Public Service Commission of Wisconsin, Generic Environmental Impact Statement on Electric Utility Rates 41-47 (1977).

92. A declining block rate design is composed of a continuum of consumption blocks, with each block having a fixed price per Kwh and each successive block having a lower price per Kwh than the block before it as the ratepayer's consumption increases. 18 C.F.R. § 290.103(a). The rate is assumed to be economically inappropriate when construction and fuel costs accelerate. Under PURPA rate design standards, state PUCs will attempt to avoid declining block rates in ratemaking. *See, e.g.*, Public Utility Commission of Texas, Rate Design Study, Final Report 47-8 (December, 1978). Although discouraging the use of the declining block rate, the report also states that the superiority of flat energy blocks has also not been demonstrated. In fact, the "average cost" rate used for utility ratemaking recovers as much of the customer costs before making decisions on rates as early in the rate schedule as possible. The report recommends that utilities be required to demonstrate specific relationships between customer load characteristics and proposed blocking arrangements with the composition of customer classes to show homogeneity within customer classes.

93. PURPA at § 210(b), 16 U.S.C. § 942a-3 (Supp. II 1978).

are available,[94] FERC's final rules for section 210 of PURPA provide that nothing within the rules requires any utility to pay more than the "avoided costs" for purchases.[95] "Avoided costs" are defined as costs to an electric utility of *energy and capacity* or both, which, but for the purchase from the cogeneration facility, the utility would generate or construct or purchase from another source.[96] The "avoided costs" concept is derived from the statutory phrase "the incremental cost to the electric utility of alternative electric energy"[97] and includes both fixed and running costs on a utility which can be avoided by the purchase of the export power.[98] Energy costs are the variable costs associated with the production of kilowatt hours and include cost of fuel and some operating and maintenance expenses.[99] Capacity costs include providing the capability to deliver energy, that is, capital costs of the facility.[100] Interconnection costs are not included in avoided costs[101] and are to be paid by the parties as assessed by the state public utility commission (PUC).[102] Under the final rules for section 210, FERC established two distinctions for setting the standard rates for purchase of power. If a qualifying facility has a design capacity of one hundred kilowatts or less, each state regulatory authority and nonregulated electric utility is required to cause standard rates to be put into effect for purchase from that facility.[103] If the qualifying facility has a capacity greater than one hundred kilowatts, the state PUC and nonregulated electric utility is permitted, but not required, to put a standard rate of

94. *See* Staff Paper Discussing Commission Responsibilities to Establish Rules Regarding Rates and Exemptions for Qualifying Cogeneration and Small Power Production Facilities Pursuant to Section 210 of PURPA, 44 Fed. Reg. 38,869-71 (July 3, 1979).

95. 45 Fed. Reg. 12,214, 12,235 (February 25, 1980) (to be codified in 18 C.F.R. § 292.304(a)(2)).

96. *Id.* at 12,214, 12,234 (to be codified in 18 C.F.R. § 292.101(6)) (*emphasis added*). "Avoided costs" can be calculated by computing the capacity and energy costs that would be incurred by a utility to meet a specified demand compared to the cost if the utility purchased the energy and capacity, or both, from a qualifying facility to meet part of its demand and supplied its remaining needs from its own facilities. The difference represents the net "avoided cost" by the utility. Here, "avoided costs" are the excess of total capacity and energy cost of the system developed in accordance with the utility's optimal capacity plan, excluding the qualifying facility, over the total capacity and energy cost of the system (before payment to the facility developed in accordance with the utility's optimal capacity expansion including the qualifying facility). *Id.* at 12,216.

97. PURPA at § 210(d), 16 U.S.C. § 824a-3 (Supp. II 1978).

98. 45 Fed. Reg. 12,215, 12,216 (February 25, 1980).

99. *Id.* at 12,216.

100. *Id.*

101. *Id.* at 12,234 (to be codified in 18 C.F.R. § 292.101(7)).

102. *Id.* at 12,236 (to be codified in 18 C.F.R. § 292.306(a)).

103. *Id.* at 12,235 (to be codified in 18 C.F.R. § 292.304(c)(1)).

purchase into effect.[104] A utility is not required to pay more than the "avoided cost" for purchase of power[105] and, if the rate is consistent with being just, reasonable, and nondiscriminatory,[106] the PUC (or nonregulated utility) may determine that a rate may be less than the "avoided cost" if it is sufficient to encourage cogeneration.[107] Factors that must be considered before the avoided cost rate can be determined include the availability of capacity and energy during the system's daily and seasonal peak periods, the ability of the utility to dispatch[108] the qualifying facility, the expected or demonstrated reliability of the facility, the terms of any legally enforceable obligation, and the extent to which facility outages can be usefully coordinated with scheduled outages of the utility. The ability of the qualifying facility to separate its load from its generation, especially during system emergencies, the aggregate capability of the capacity obtained from qualifying facilities to displace planned utility capacity, and the lead time associated with the addition of capacity from the qualifying facility compared to lead time required if the utility constructed its own unit are to be included.[109]

In order to estimate avoided costs, FERC rules require that qualifying facilities must be furnished with data by the utilities concerning present and future costs of energy and capacity on the utility system.[110] State regulatory authorities are responsible for implementing the arrangements between electric utilities and qualifying facilities under Subpart C of section 210 of PURPA.[111] Implementation may consist of regulations that undertake to resolve disputes that have arisen under Subpart C between qualifying facilities and electric utilities on a case by case basis. Such disputes might involve matters of backup or maintenance power supply, rates, periods of purchase, and other problems identified in Subpart C.[112] The state implementation may cover all sections of Subpart C except for sections that will be governed by 18

104. *Id.* at 12,235 (to be codified in 18 C.F.R. § 292.304(c)(2)).
105. *Id.* at 12,235 (to be codified in 18 C.F.R. § 292.304(a)(2)).
106. *Id.* at 12,235 (to be codified at 18 C.F.R. § 292.304(a)(i)(ii)).
107. *Id.* at 12,235 (to be codified at 18 C.F.R. § 292.304(a)(3)).
108. Dispatching is the ability of a utility to control, from a central location, the generated power it is receiving. This allows it to respond to fluctuations in demand. *Id.* at 12,226.
109. *Id.* at 12,226-27 (to be codified in 18 C.F.R. 292.304(c)(2)).
110. *Id.* at 12,218, 12,234 (to be codified in 18 C.F.R. § 292.302(b)).
111. *Id.* at 12,236-37 (to be codified in 18 C.F.R. § 292.401(a)).
112. *See id.* at 12,234-36 (to be codified in 18 C.F.R. §§ 292.303-292.308).

C.F.R. section 292.302.[113]

Prior to the issuance of the final FERC rules for section 210, industries had contended that their facilities or financing ventures for cogeneration would subject them to regulations as a public utility under PUCHA or because of sales to the utility grid. Utilities and industry developed legal devices to protect the industry from such regulation.[114] However, in order to encourage cogeneration, FERC's final rules for section 210 exempt qualifying facilities from all provisions of PUHCA that are related to public utilities.[115] While the necessity for such legal devices to avoid regulation as a public utility has disappeared, some concern still remains that regulation will occur on the state level.

Although steam prices are not regulated under PURPA, state PUCs do have the existing authority to review contracts for purchases entered into by the utilities they regulate, and would review the contracts for steam and electric power purchase entered into by the utility and the qualifying facility.[116]

Pricing for excess power, as stated earlier, should turn on supply and load management. These are factors which are highly variable and subject to many sub-factors. Because of this, some concern was expressed to FERC that negotiations for purchase pricing between the utility and industry allow for decisions by the parties that take into account all the factors which could never be reached through government ratemaking as set out under PURPA. For example, is the industrial cogenerator able to assure a constant excess power supply to the utility or will it sell its excess only during off-peak periods? Will off-peak purchases to the utility match the timing and quantity needs for the load management of the utility's system? How reliable will the cogeneration unit actually be in meeting projected output or will the utility need to provide a reserve resource? What rates of return will the cogenerator return on his capital costs which are higher than the utility

113. *Id.* at 12,237 (to be codified in 18 C.F.R. § 292.401(a)). 18 C.F.R. § 292.302 governs the availability of electric utility system cost data.

114. Barrett, Cogeneration - Ventures, *supra* note 47, at 10. An excellent example of a contract designed to avoid regulation as a public utility is the one between Celanese Corporation (for its Pampa, Texas, chemical plant) and Southwestern Public Service Company. See Application of Southwestern Public Service Co. For a Certificate of Convenience and Necessity, No. 703 (filed September 20, 1977 with the Public Utility Commission of Texas).

115. 45 Fed. Reg. 12,215, 12,237 (February 25, 1980) (to be codified in 18 C.F.R. § 292.602(b)).

116. *See id.* at 12,233 (discussing the intended impact of 18 C.F.R. §§ 292.301(b)(1) and 292.602(c)).

costs because of the lower risk of the utility and its economies of scale? What portion of return shall be derived from the cogenerator's steam takeoff and what portion from the purchases made by the utility? Since a utility's fuel costs are higher than a cogenerator's fuel costs, how will the fuel cost adjustments reflect this difference between the cogenerator and the utility for the energy purchased?[117]

Questions such as these were raised during FERC rule hearings and in written comments. The final rules provide that the rate of purchase will meet the statutory requirements if the rate is set after the consideration of the seven factors stated above (listed in 18 C.F.R. section 292.306(e)) and on the basis of system cost data set forth pursuant to 18 C.F.R. section 292.306(b) and (c), if the rate equals no more than the avoided costs.

4. Tax

The 1977 drafts of the NEA included specific tax provisions in addition to the existing investment tax credits as financial motivation for the development of both utility and industrial cogeneration facilities.[118] The additional tax credit did not materialize in the final Energy Tax Act (ETA) of 1978. Three categories of energy property were identified that might be treated as qualifying for the existing investment tax credit in section 38 of the Internal Revenue Code of 1954.[119] "Energy property,"[120] for the period beginning October 1, 1978, and ending December 31, 1982, is to be treated as meeting the requirements of section 38 "tax property," which is depreciable property eligible for the ten percent investment tax credit.[121] Cogeneration equipment, while not listed in the definitions of "energy property," should still qualify for the ten percent investment tax credit in section 38.[122] Certain types of energy property might also fall within the "alternative energy property"[123] classification and qualify cogenerators for the ten percent energy tax credit for that property. The "alternative energy property" term can include boilers or burners if the primary fuel will be an alternate sub-

117. Seplow, Obstacles and Opportunities, *supra* note 73, at 7.
118. H.R. REP. 543, 95th CONG., 2d SESS. 57, *reprinted in* 6 U.S. CODE CONG. & AD. NEWS 7723-24 (1978); S. REP. 529, 95th CONG., 2d SESS. 80-3, *reprinted in* 6 U.S. CODE CONG. & AD. NEWS 8011-14 (1978).
119. I.R.C. § 38.
120. I.R.C. § 48(l)(2).
121. *Id.*
122. *See* I.R.C. § 48(l).
123. I.R.C. § 48(l)(3).

stance (one other than oil or gas).[124] The definition for "specially defined energy property" includes the type of properties which reduce the amount of energy consumed in any existing industrial or commercial process and which are installed in connection with an existing industrial or commercial facility in retrofit.[125] Certain of these items could be used by the cogenerator in a unit design and receive the ten percent tax credit.[126]

Although FERC did not have the power in its rulemaking to determine what properties would receive investment tax credit, it did express the opinion that "energy property" owned by qualifying cogenerators should not be classified as "public utility property."[127] "Public utility property" is excluded from investment tax credit within the meaning of section 46(f)(5) of the Internal Revenue Code of 1954.[128] The Commission observed that if such property were not classified as "public utility property," the qualifying facility would be eligible for investment tax credit set out in section 301(b) of ETA.[129] The final rules which exempt qualifying facilities from definition as a "public utility" reflect the Commission's intent to provide cogeneration incentives wherever possible. However, any energy tax credit is statutorily scheduled to expire in 1982.[130] With the extensive time required for siting and construction of a new facility, the qualifying facility will forego much of that period and the tax credit that would have been available during that period.

In addition to energy tax credits under the provisions of ETA, possibilities of tax exempt financing also exist.[131] PURPA extends cogeneration regulation to any qualified small power production facilities.[132] Under this definition, municipal solid waste processing facilities could be used to generate industrial electricity from waste heat during the processing. The promotion of the "integrated community energy

124. I.R.C. § 48(l)(3)(A)(i).
125. I.R.C. § 48(l)(5).
126. These items might include such things as a coal-fired boiler, coal handling equipment, and air pollution control equipment.
127. 45 Fed. Reg. 12,214, 12,228 (February 25, 1980). The Treasury Department's regulations provide that the definition of public utility property does not include property used in the business of furnishing or sale of electric energy if the rates are not subject to regulation that fixes a rate of return on investment. Treas. Reg. § 146-3(g)(2), T.D. 7602 (March 23, 1979).
128. I.R.C. § 46(F)(5).
129. 45 Fed. Reg. 12,214, 12,228 (Feb. 25 1980).
130. I.R.C. § 48(l)(1).
131. Address by Roger Feldman, Realizing the Promise of Cogeneration, Energy Bureau, Inc. 15 (March 5, 1979) [hereinafter cited as Feldman, The Promise of Cogeneration].
132. PURPA, § 201(17)(c), 16 U.S.C. § 796 (Supp. II 1978).

system" is based on just such a concept as this. An interconnected cogeneration facility owned by a public power authority could be financed by tax exempt bonds and then provide an industrial firm with a proportion of the power facility's capacity.[133] For tax exemption purposes, the industrial firm would have to confine its proportion of capacity purchased by a take-or-pay contract to under twenty-five percent of the facility capacity, and the industry's annual payments could not equal or exceed more than three percent of the average annual debt service amount.[134] Although technical issues for such authorities need to be examined, such projects appear feasible.

In summary, although progress has been toward creating incentives, strong disincentives for cogeneration still exist in all areas—development, capital cost, pricing, and tax incentives. Capital investment in expensive cogeneration equipment receives no tax credit other than the possible ten percent investment tax credit available for energy property. The required standards for rates of purchase for excess power have yet to be set and implemented by state PUCs. While the final rules also exempt the qualifying facility from certain regulation under FPA, regulation as a public utility under PUHCA, and state regulatory ratemaking, FERC rules do determine that the power must be sold and purchased, that the rates will include specific factors, and the state PUCs are to implement these rules. The federal legislation does not go far enough toward developing the potential for cogeneration as a fuel conservation technique. Public policy is directed foremost toward electric power generation for the utility grid. The efficient use of fuel to produce other forms of energy such as shaft horsepower is not rewarded. Long-range outcomes for cogeneration are not predictable except in the sense that only cogeneration for electricity production will be favored for the energy future of the United States.

C. *Regulatory Issues*

Many of the concerns of industry that industrial electrical power cogeneration facilities would be regulated as public utilities have faded with FERC's promulgation of final rules for sections 201 and 210 of PURPA which became effective in March of 1980. Industry has been specifically exempted from three areas of regulations. Qualifying facilities are exempted from the jurisdiction of most of the FPA and shall

133. Feldman, The Promise of Cogeneration, *supra* note 131, at 15.
134. *Id.*

not be "electric utility" companies under section 2(a)(3) of PUHCA.[135] They are also to be exempt from state regulation in the areas of rates of electric utilities and financial and organizational regulation of electric utilities.[136] Qualifying facilities are subject to regulation under the FERC rules for PURPA which will be implemented by state PUCs.[137] The rules have also resolved questions about the sale and purchase of power, qualifications for cogeneration facilities, and types of cogeneration included under the Act which will be discussed later.

Pricing concepts of purchase of power at market value or equivalent power have been replaced with a rate based on "avoided cost." Size, fuel use, and fuel efficiency criteria were discarded as qualifications of a cogenerating requirement for facilities even though the statute would have allowed this.[138] The provision of additional services such as maintenance power and backup power to the qualifying facility will be required of utilities upon request by a facility.[139] Residential cogeneration is also entitled to the benefits of the regulation as well as industrial and commercial cogeneration.[140]

The incentives and fears which existed a year ago because FERC regulations were not yet known should be alleviated by the broad exemptions in the final rules which were intended to provide further incentives for the development of cogeneration. It should be noted that the discussion of the regulations which follows *does not* include regulations relating to small power production plants.

1. Regulatory Issues in General

As stated previously, the legal issues related to cogeneration of electric power have arisen primarily from the fear of potential cogenerators that they would be regulated as a utility under FPA, PUHCA, FERC rules for PURPA, and state PUC ratemaking. Under the FPA, FERC has jurisdiction over the transmission of electric energy in interstate commerce and the sale of electric energy to any person for whole-

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135. 45 Fed. Reg. 12,214, 12,237 (February 25, 1980) (to be codified in 18 C.F.R. § 292.602(b)). PUCHA defines electric utilities in 15 U.S.C. § 79b(a)(3) (1976).
136. 45 Fed. Reg. 12,214, 12,237 (February 25, 1980) (to be codified in 18 C.F.R. §§ 292.601(a)(b), 292.602(a)(b)(c)(1)(i-ii)).
137. *Id.* at 12,236 (to be codified in 18 C.F.R. § 292.401(a)).
138. PURPA, § 201(17)(L), 16 U.S.C. § 796(18)(B)(i) (Supp. II 1978).
139. 45 Fed. Reg. 12,214, 12,236 (February 25, 1980) (to be codified in 18 C.F.R. § 292.305(b)(1)).
140. *See id.* at 17,960 (March 20, 1980). In discussing 18 C.F.R. § 292.202(c) FERC stated that despite the lack of explicit language in PURPA including residential cogeneration, FERC intends to interpret the statute to include this. *Id.*

sale in interstate commerce.[141] An operator of a facility is defined as a "public utility" under FPA if it is involved in either of these two activities.[142] Under federal regulation, the facility is subject to rate regulation for any sale of power in interstate commerce, prescribed utility and management accounting practices and regulation of sales of its securities which are not state regulated.[143] The threat of regulation under the FPA, whether real or imagined, has been the primary and initial legal problem which has impeded industrial interest in cogeneration. The industrial cogenerator thought that if power were utilized by only his project and its owners, or the project were set up within a subsidiary, which then made the required reports to the SEC, or if sales of excess power were limited to a rate schedule with a local utility, the cogeneration project would not come under future FERC regulations since the power would not enter interstate commerce or the subsidiary would be exempt from PUHCA, or both.[144] The industrial cogenerator also feared that the sale of excess power to the public utility system engaged in interstate commerce would subject the facility to regulation as a public utility. An electricity producing cogeneration facility set up as a subsidiary of an operating company would be subject to registration as a "holding company" under PUHCA if the "person" directly or indirectly controlled ten percent of the voting securities of an electric utility company or exercised a controlling influence over an electric company.[145]

Section 210(e) of PURPA provides that FERC can exempt qualifying facilities from federal regulation under the FPA, and from state regulation regarding utility rates and financial and organization reporting if the Commission determines such exemptions are necessary in order to encourage cogeneration.[146] FERC used this broad authority to exempt qualifying cogeneration facilities from all but certain specified sections of the FPA. However, no qualifying facility may be exempt from the licensing requirements of Part I of the FPA nor from section 202(c) of PURPA which requires the facility to provide energy if the

141. The Federal Power Commission had this authority under the FPA, § 201, 16 U.S.C. § 824(a) (Supp. II 1978). The authority was transferred to FERC by the DOE Organization Act, 42 U.S.C. §§ 7151, 7172 (Supp. II 1978).

142. § 201, 16 U.S.C. § 824(e) (Supp. II 1978).

143. *Id.* at §§ 824a, 824c, 824e, 825 (Supp. II 1978).

144. Roger Feldman, Legislation and Regulation, Energy Bureau, Inc. 4-6 (1977). This paper contains several suggestions for possible exemptions from PUCHA.

145. PUCHA, 15 U.S.C. § 796(a)(3),(5),(7)(a),(8)(a) (Supp. II 1978).

146. PURPA, § 210(e), 16 U.S.C. § 824a-3(e)(1) (Supp. II 1978).

Economic Regulatory Administration determines an emergency situation exists.[147]

No qualifying facility may be exempt from sections 210 ("Certain Interconnection Authority"), 211 ("Certain Wheeling Authority"), and 212 ("Provisions Regarding Certain Orders Requiring Interconnection or Wheeling) of the FPA.[148] The qualifying facility is also subject to the jurisdiction of FERC for carrying out and enforcing the provisions of these sections.[149] Section 210 of the FPA (section 202 of PURPA) is concerned with interconnection authority of the Commission, that is:

> Upon application of any electric utility, Federal Power marketing agency, qualifying cogenerator, or qualifying small power producer, the Commission may issue an order requiring—
>
> (A) the physical connection of any cogeneration facility, any small power production facility, or the transmission facilities of any electric utility, with the facilities of such applicant,
>
> (B) such action as may be necessary to make effective any physical connection described in subparagraph (A), which physical connection is ineffective for any reason, such as inadequate size, poor maintenance, or physical unreliability,
>
> (C) such sale or exchange of electric energy or other coordination, as may be necessary to carry out the purposes of any order under subparagraph (A) or (B), or
>
> (D) such increase in transmission capacity as may be necessary to carry out the purposes of any order under subparagraph (A) or (B).[150]

Section 211 of FPA (Section 203 of PURPA) concerns wheeling authority[151] for an order from the Commission requiring an electric utility to provide transmission services to the applicant or transmission services to an applicant purchasing electric energy for resale from that utility.[152] Section 212 of FPA (Section 204 of PURPA) sets forth cer-

147. 45 Fed. Reg. 12,214, 12,237 (February 25, 1980) (to be codified in 18 C.F.R. § 292.601(b)(1-2)).
148. PURPA, § 210(c)(3)(B), 16 U.S.C. § 824a-3(e)(3)(B) (Supp. II 1978).
149. *Id.*
150. *Id.* at § 824i-(a)(1)(A-D).
151. Wheeling is a term used to denote "the transmission of electric power from one producer to a second party over the transmission lines of a third party." Dow Chemical Co., Industrial Center Study, *supra* note 41, at 62.
152. PURPA, § 203, 16 U.S.C. § 824j (Supp. II 1978).

tain determinations FERC must make before it can issue an order under sections 210 or 211 of FPA.[153] The Commission observed, however, that requiring qualifying facilities to go through the complex procedures required within section 210 to gain interconnection would frustrate and restrict the participation and market development of cogenerators if these procedures were the only means for obtaining interconnection with utilities.[154] FERC rules provide that an electric utility must interconnect with any qualifying cogeneration facility as may be necessary to accomplish purchases or sales with the facility, but no electric utility is required to interconnect with any facility, if, solely by reason of purchases and sales over the interconnection, a utility not subject to federal jurisdiction would become subject to federal utility regulation.[155] A state PUC or nonregulated electric utility must enforce this obligation to interconnect since implementation of the FERC rules is left to state PUCs.[156] FERC exempted qualifying facilities from FPA's traditional rate regulation and regulation of the securities of public utilities.[157] Qualifying facilities are required to meet reporting requirements regarding interlocking directorates under section 305(c) of FPA and they are also subject to any enforcement provisions of Part III of the FPA which relate to any sections of the FPA that apply.[158]

Under section 210(e) of PURPA, FERC can exempt qualifying cogeneration facilities from regulation under PUHCA and state laws and regulations governing rates or financing and organization.[159] The Commission rules provide a broad exemption for facilities from the definition of "electric utility company" under section 2(a)(3) of PUHCA,[160] thus removing qualifying facilities from all PUHCA regulation provisions related to electric utilities. While qualifying facilities are exempt from state laws and regulations respecting rates and financial and organization regulation of electric utilities, they are still subject to the state laws or regulations which will implement subpart C of the FERC rules for PURPA.[161] States are not divested of authority under state law to review contracts for purchase of power as part of the

153. *Id.* at § 204, 16 U.S.C. § 824k (Supp. II 1978).
154. 45 Fed. Reg. 12,214, 12,220-21 (February 25, 1980).
155. *Id.* at 12,235 (to be codified in 18 C.F.R. § 292.303(c)(1),(2)).
156. *See id.* at 12,236-37 (to be codified in 18 C.F.R. § 292.401(a),(b)).
157. *Id.* at 12,237 (to be codified in 18 C.F.R. § 292.601(b)).
158. *Id.* at 12,237 (to be codified in 18 C.F.R. § 292.601(b)(4)).
159. 16 U.S.C. § 824a-3(e)(1) (Supp. II 1978).
160. 15 U.S.C. § 79b(a)(3) (1976).
161. 45 Fed. Reg. 12,237 (February 25, 1980) (to be codified in 18 C.F.R. § 292.602(c)(2)).

state's regulation of electric utilities, if the state authority is consistent with the terms and policies of sections 201 and 210 of PURPA.[162] States may seek interpretive rulings on the state's authority from FERC as well as request that the Commission limit the applicability of the broad exemption from state law.[163] A facility may request an interpretation from FERC as to whether it is subject to a particular state law.[164]

In summary, FERC's rules under PURPA reorder the jurisdictions of federal regulation over sales for resale in interstate commerce and state regulation over retail intrastate sales. FERC rules for cogeneration purchases and sales will govern, whether the transaction is for interstate commerce or local retail sale. Several state actions may still subject qualifying cogeneration facilities indirectly to certain forms of state regulation. States may still require site proceedings for the construction of a facility, or PUC evaluation and study of cogeneration records for system-wide demand forecasting, or power supply advance planning.[165]

2. Specific Regulatory Issues

Rates for purchase set forth under FERC rules must be just, fair, and reasonable to electric consumers of the electric utility, in the public interest, and not discriminatory against qualifying facilities.[166] The rates cannot exceed the incremental costs of alternative electric energy, that is, the costs of energy to the utility which, but for the purchase, the utility would generate itself or purchase from another source.[167] The calculation of the resulting "avoided cost" may be made in one of two ways. The purchase price for the power can be pursuant to a legally enforceable contract or the "avoided cost" may be computed for the power "as available" at the time of delivery.[168]

The "avoided cost" as a purchase price standard will not produce rate savings to utility customers. In fact, customers will pay the same rates as if the utility had generated the power and not purchased energy and capacity from the qualifying cogeneration facility. The standard's

162. *Id.* at 12,233.
163. *Id.* (to be codified in 18 C.F.R. § 292.602(c)(3)).
164. *Id.* (to be codified in 18 C.F.R. § 292.602(c)(4)).
165. Feldman, Promise of Cogeneration, *supra* note 127, at 16-17.
166. 45 Fed. Reg. 12,214, 12,235 (February 25, 1980) (to be codified in 18 C.F.R. § 292.304(a)(i-ii)).
167. PURPA, § 210(b), 16 U.S.C.A. § 824a-3(b),(d) (Supp. II 1978).
168. 45 Fed. Reg. 12,214, 12,235 (February 25, 1980) (to be codified in 18 C.F.R. § 292.304(d)).

broad intent is to benefit the nation as a whole by decreasing reliance on scarce fossil fuels, encouraging energy efficiency, and providing incentive for cogenerators.[169] Facilities commenced before PURPA may have rates established by the state at full avoided costs or at a lower rate if the state PUC determines that the lower rate provides sufficient encouragement for the facility.[170] If the previously existing "old capacity" facility (one built before PURPA) can show it needs the full "avoided costs" to remain viable or increase output, the PUC is required to establish that rate.[171]

New capacity is any purchase from a qualifying facility on which construction commenced after November 8, 1979.[172] Utilities must pay a rate equal to the avoided cost from a new capacity facility.[173] The FERC rules require the utility to purchase at its "avoided cost" the total output made available by a "new capacity facility," even if the utility simultaneously sells energy to the facility at its retail rate.[174] State PUCs are *required* to put into effect standard rates for purchases by each electric utility from a facility with a design capacity of 100 kilowatts or less.[175] Standard rates for facilities with design capacity of more than 100 kilowatts *may* be put into effect.[176] FERC made the distinction so that facilities of lesser size would be spared the administrative costs of transacting individualized rates.[177] Standard rates may differ for facilities using various technologies on the basis of the supply characteristics of that technology.[178]

Factors relative to the availability and reliability of the excess power and of the ability of the qualifying cogeneration facility to fit the electric utility generating mix are to be considered in determining purchase rates.[179] Facilities of 100 kilowatts or less can aggregate and increase assured energy and capacity from dispersed systems for purchase by the electric utility and the rates for this power should take

169. *Id.* at 12,222.
170. *Id.* at 12,235 (to be codified in 18 C.F.R. § 292.304(b)(3)).
171. *Id.* at 12,223.
172. *Id.* at 12,235 (to be codified in 18 C.F.R. § 292.304(b)(1)).
173. *Id.* (to be codified in 18 C.F.R. § 292.304(b)(4)).
174. *Id.* (to be codified in 18 C.F.R. § 292.304(a), (b)).
175. *Id.* (to be codified in 18 C.F.R. § 292.304(c)(1)).
176. *Id.* (to be codified in 18 C.F.R. § 292.304(c)(2)).
177. *Id.* at 12,224.
178. *Id.* at 12,235 (to be codified in 18 C.F.R. § 292.304(c)(1)-(3)(ii)). An example of such difference might be when a system peak occurs on days when there is bright sun and no wind. Rates for purchase could provide a higher capacity payment for photovoltaic cells than for wind energy conversion systems. *Id.* at 12,225.
179. *Id.* (to be codified in 18 C.F.R. § 292.304(e)).

this into account.[180] Purchase of energy and capacity is not required of the electric utility during periods when, because of operational circumstances, purchases will result in net increases in operating costs to the utility.[181] Such periods must be due to operational circumstances, in particular the certain conditions which can occur during light loading periods which limit the base load units' ability to increase output level rapidly if the unit has attempted to accommodate surcharges from qualifying facilities.[182] Notice to cease purchasing must be given to the facility, or the utility is required to reimburse the facility as if the energy and capacity had been received.[183]

Rates for sales to the facility will not be considered discriminatory if based on accurate data and consistent system-wide costing principles which also apply to other similar customers.[184] Upon request, the utility must provide the facility additional services to include supplementary, backup, maintenance and interruptible power. These services may be waived, however, if, after notice and opportunity for comment, the utility can demonstrate and the state PUC finds, that compliance impairs the utility's service delivery to customers or places an undue burden on the utility.[185] Rates for sales of backup and maintenance power shall not be based on the assumption that forced outages or reduced output by a qualifying facility will occur simultaneously through the system or during the peak. Scheduled outage rates must take into account the coordination with the utility's scheduled outages.[186] State regulatory authorities have until March 20, 1981, to implement these FERC rules on section 210 of PURPA.[187]

Who can qualify as a cogenerator? The final rules for section 201 of PURPA set forth criteria and procedures by which cogeneration facilities can obtain qualifying status to receive rate benefits and the exemptions promulgated by FERC for section 210 of PURPA. The Commission determined that section 201 of PURPA allowed the Commission to include requirements for minimum size, fuel use, and fuel efficiency for qualifying facilities, but the Commission was not *required* to set these specific requirements. The final rules reflect the Commis-

180. *Id.* at 12,236 (to be codified in 18 C.F.R. § 292.304(e)(vi)).
181. *Id.* (to be codified in 18 C.F.R. § 292.304(f)(1)).
182. *Id.* at 12,227.
183. *Id.* at 12,236 (to be codified in 18 C.F.R. § 292.304(f)(2)).
184. *Id.* at 12,236 (to be codified in 18 C.F.R. § 292.305(a)(2)).
185. *Id.* (to be codified in 18 C.F.R. §§ 292.305(b)(1)(i-iv) and (b)(2)(i-ii)).
186. *Id.* (to be codified in 18 C.F.R. § 292.305(c)(1)-(2)).
187. *See id.* (to be codified in 18 C.F.R. § 292.401(a)).

sion's intent not to do so.[188]

With the exception of new diesel facilities, there are two general requirements for qualification of cogeneration facilities: the facility must meet an ownership test and must meet specific operating and efficiency standards.[189] If a facility wants to qualify for the incremental pricing exemption under Title II of section 206(c)(3) of the Natural Gas Policy Act of 1978 (NGPA),[190] it must use natural gas in a topping cycle for other than supplemental firing, meet the operating and efficiency standards for a topping cycle, and be a qualifying facility which meets any applicable operating efficiency standards.[191] Bottoming cycle plants not subject to an exemption from incremental pricing under Subpart E of NGPA are eligible for exemption from Title II of section 206(c) of NGPA to the extent that reject heat emerging from the useful thermal energy process is available for power production.[192] FERC may waive any of the operating and efficiency criteria for facilities upon a showing that the facility will produce significant energy savings.[193]

A cogeneration facility must also meet the ownership criteria and may not be owned by a person primarily engaged in the generation or sale of electric power.[194] The ownership test requires that a cogeneration facility cannot hold more than fifty percent of the equity interest in the facility as an electric utility, a public holding company utility, or combination thereof. If a wholly or partially owned subsidiary of an electric utility or public utility holding company has an ownership interest of a facility, it will be considered ownership by the electric utility or public utility holding company.[195]

Criteria for qualifying cogeneration facilities specifically require that the cogeneration process include the "sequential use of energy," that is, that the rejected heat from a power production or heating process is used in another power production or heating process.[196] The tests for meeting operating and efficiency standards have been delineated in

188. *Id.* at 17,959, 17,963 (March 20, 1980) (to be codified in 18 C.F.R. § 292.203(b)).
189. *Id.* at 17,972 (to be codified in 18 C.F.R. § 292.203(b)(i-ii)).
190. 15 U.S.C.A. § 3346 (Supp. II 1978).
191. 45 Fed. Reg. 17,959, 17,973 (March 20, 1980) (to be codified in 18 C.F.R. § 292.205(c)(4)(a), (c)(1)(i-ii)).
192. *Id.* (to be codified in 18 C.F.R. § 292.205(c)(2)).
193. *Id.* (to be codified in 18 C.F.R. § 292.205(d)).
194. *Id.* (to be codified in 18 C.F.R. § 292.206(a)).
195. *Id.* (to be codified in 18 C.F.R. § 292.206(b)).
196. *Id.* at 17,972 (to be codified in 18 C.F.R. § 292.202(c)).

the final rules to distinguish between operating and efficiency standards for "topping" cycle cogeneration facilities and for "bottoming" cycle cogeneration facilities.[197] The topping cycle (wherein the energy input of the facility is first used to produce useful power output and the reject heat from power is then used to provide useful thermal energy) operating standards require that the useful energy output of the facility must be no less than five percent of the total energy output during any calendar year.[198] The efficiency standard has several requirements. If any of the energy input of a topping cycle facility is natural gas or oil and the installation began on or after March 13, 1980, then the useful power output of the facility and one-half of the useful thermal energy output for the calendar year must be (1) no less than forty-two and one-half percent of the total energy input of natural gas and oil to the facility or, (2) if the useful thermal energy output is less than fifteen percent of the total energy output of the facility, no less than forty-five percent of the total energy input of natural gas and oil to the facility.[199] Any topping cycle facility not using natural gas or oil and installed before March 13, 1980, is not subject to this efficiency standard.[200]

For bottoming cycle facilities whose installation began on or after March 13, 1980, and for which any of the energy input as supplementary firing is natural gas or oil, the efficiency standard requires that the useful power output during any calendar year be not less than forty-five percent of the energy input of the natural gas and oil.[201] The total energy input mentioned in the standards is to equal the total energy of all forms supplied from external sources other than supplemental firing to the facility. Supplementary firing is an energy input to the facility used only in the thermal process of a topping cycle or only in the electric generating process of a bottoming cycle.[202] The distinction is made since the energy for supplemental firing is not used sequentially in the cogeneration process as called for in the definition of a cogeneration facility. The regulations also provide that bottoming cycle facilities (like a topping cycle facility) existing before March 12, 1980, have no efficiency standard requirement.[203]

Cogeneration facilities are frequently complex combinations of

197. *See id.* at 17,973 (to be codified in 18 C.F.R. § 292.205).
198. *Id.* (to be codified in 18 C.F.R. § 292.205(a)(1)).
199. *Id.* (to be codified in 18 C.F.R. § 292.205(2)(i)(A)-(B)).
200. *Id.* (to be codified in 18 C.F.R. § 292.205(2)(ii)).
201. *Id.* (to be codified in 18 C.F.R. § 292.205(b)(1)).
202. *Id.* at 17,972 (to be codified in 18 C.F.R. § 292.202(f)).
203. *Id.* at 17,973 (to be codified in 18 C.F.R. § 292.205(b)(2)).

these cycles. To aid a facility in determining whether it will qualify for cogeneration status and exemptions, the facility may inquire of the Commission in regard to applicability of the standards to its particular design. A procedure is also available for a facility wanting clarification on its qualification application.[204] Any of the standards may be considered for waiver by the Commission upon a showing that the facility will produce significant energy savings.[205] One type of facility, a new diesel cogenerating facility, is excluded from qualification until the environmental impact statement for this technology has been completed.[206]

The procedures for obtaining qualifying status provide that the cogeneration facility must meet the requirements set out in 18 C.F.R. section 292.203(b) (regarding ownership, operating, and efficiency criteria) and the owner or operator must also furnish notice to the Commission setting forth specific information which includes (1) the name and address of the owner and location of the facility, (2) a brief description of the facility indicating it is a cogeneration facility, (3) the primary energy source used or to be used by the facility, (4) the power production capacity of the facility, (5) the percentage of ownership by any electric utility, public holding company, or by any person owned by either, (6) a description of the system including whether the facility is a topping or bottoming cycle facility and sufficient information to show whether qualifying cogeneration requirements are met, and (7) the date the facility installation began or will begin.[207]

Once applications are filed, the Commission must issue an order within ninety days which grants or denies the application, tolls the time for issuance of an order, or sets the matter for hearing. Any denial orders must identify the specific requirements which were not met, and if no order is issued within ninety days of filing, the application is deemed granted.[208] If the application shows the facility has a design capacity of 500 kilowatts or more, the electric utility is not required to purchase power until ninety days after the facility notifies the utility it is a qualifying facility, or ninety days after the facility has applied to the Commission.[209] The Commission may revoke a certification if the

204. *Id.* (to be codified in 18 C.F.R. § 292.207).
205. *Id.* (to be codified in 18 C.F.R. § 292.205(d)).
206. *Id.* at 17,964, 17,972 (to be codified in 18 C.F.R. § 292.203(c)(1)).
207. *Id.* at 17,973 (to be codified in 18 C.F.R. § 292.207(b)(2)(i-v)).
208. *Id.* (to be codified in 18 C.F.R. § 292.207(b)(5)).
209. *Id.* at 17,974 (to be codified in 18 C.F.R. § 292.207(c)).

facility does not comply with statements in its application.[210] To avoid any problems with design changes or alterations, a qualifying facility that has been certified may apply for a determination that any alteration or modification in the facility will not revoke its status.[211]

In summary, the long awaited rules from FERC for cogeneration set up the procedures the Commission will use to qualify applicant facilities according to type of generating cycle. The promulgated rules for the pricing of the purchase of excess power are to be implemented by individual state PUCs and, thus, will reflect regional differences and circumstances and the enormous range of characteristics in power production.

IV. Conclusion

Long-range planning is necessary if the United States is to establish any viable and realistic energy policy for our finite energy resources and the technologies yet to be developed. The potential of cogeneration as a conservation technology is well understood and accepted, yet statutory incentives and definitions limit its development to concepts of electric power energy. Governmental rules and regulations to this end characterize the future of cogeneration in terms of the electric power future in the United States. Hence, the development of the technology is restricted to the parameters of the development of electric energy within the setting of a regulated monopoly. Whether this precludes longer-range planning for the cost and benefit of cogeneration's use as an alternative growth pattern for our energy needs remains to be seen. Present planning for cogeneration, however, seems to typify the state of the art today in planning for energy resources and policy in the United States.

210. *Id.* (to be codified in 18 C.F.R. § 292.207(d)(1)).
211. *Id.* (to be codified in 18 C.F.R. § 292.207(d)(2)).