

Report of the Committee on Non-Utility Generation

I. LEGISLATIVE DEVELOPMENTS

In 1992, the long-fought battles over reform of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79a, (PUHCA) were resolved with the enactment of the Energy Policy Act of 1992 (1992 Act).¹ Title VII of the 1992 Act amended PUHCA to, among other things, create the Exempt Wholesale Generator (EWG). An EWG is an entity determined by the FERC to be engaged directly, or indirectly through upstream owners, exclusively in the business of owning and/or operating all or part of one or more “eligible facilities” (defined below) and selling electric energy at wholesale.² New section 32(e) provides that an EWG will not be considered to be an “electric utility company” under PUHCA, thereby insulating the EWG’s upstream owners from PUHCA “holding company” status.³

An EWG may be an individual, association, corporation, partnership or other entity that directly owns all of an eligible facility.⁴ It may also be an entity which directly owns a part of one or more eligible facilities.⁵ The definition contemplates “EWG holding companies” which own subsidiaries that are either EWGs or companies that own only EWGs.

An EWG is not limited to sales of wholesale power *generated by* an eligible facility (or part thereof). The 1992 Act’s Conference Report states that the EWG definition “has been drafted to permit an EWG to sell wholesale power that it has not generated itself . . . [it] would permit an EWG, for example, to generate 350 Megawatts and purchase an additional 50 Megawatts in order to meet a purchaser’s 400 MW capacity need.”⁶

An “eligible facility” is a facility which is either (1) used for the generation of power exclusively for sale for resale, or (2) used for the generation of power and leased to one or more public utilities.⁷ An “eligible facility” includes interconnecting transmission facilities necessary to effect wholesale sales.⁸ Eligible facilities located in foreign countries can make retail sales, so long as no power is sold to U.S. retail consumers.⁹

The term “facility” is not defined, but seems to refer broadly to an electric generating unit and associated interconnection/transmission equipment. The 1992 Act explicitly contemplates that an eligible facility may include part of a “facility,” the remaining portion of which is in rate base as of the date of the bill’s enactment provided that the state regulators’ consent, described in

1. Pub. L. No. 102-486, 106 Stat. 2776 (1992).

2. 15 U.S.C. § 79z-5a(a)(1) (Supp. IV 1992).

3. *Id.* § 79z-5a(e).

4. *Id.* § 79z-5a(a)(1).

5. *Id.*

6. H.R. CONF. REP. NO. 1018, 102nd Cong., 2d. Sess. 388 (1992).

7. 15 U.S.C. § 79z-5a(a)(2).

8. *Id.*

9. *Id.* § 79z-5a(b).

new PUHCA section 32(c), is obtained.¹⁰ The provision does not expressly address other possible scenarios for "hybrid" generating facilities — for example, those which also generate power for internal consumption by the facility's owner. Such structural approaches are not barred, however, on the face of the statute.

However, new PUHCA section 32(d) provides that no EWG may own or operate a portion of a facility if any other portion of the facility is owned or operated by a PUHCA "electric utility company" that is an affiliate of such EWG, except that an EWG may own such a facility portion if state commission consent to its "spin-off" from existing rate base assets has been secured.¹¹ Because of the breadth of PUHCA's "electric utility company" definition, this ban can apply to EWG-affiliated entities that are not traditional public utilities. It is also important to note that PUHCA's sweeping definition of "affiliate" applies here and elsewhere in the 1992 Act, covering, *inter alia*, direct or indirect downstream subsidiaries in which the EWG holds a 5% or greater interest.¹²

Significantly, EWG rate filings will be subject to rate reasonableness review under sections 205 and 206 of the Federal Power Act (FPA). Under new section 214 of the FPA, no rate for the sale of EWG power will be deemed lawful under section 205 if the FERC determines, after notice and opportunity for hearing, that such rate results from any "undue preference or advantage" from an electric utility which is an affiliate company of the EWG.¹³

The 1992 Act gives state regulators considerable authority over EWGs and potentially expands the role of state commissions in the oversight of purchased power. New PUHCA section 32(k) bars an electric utility from entering into a power purchase contract with an EWG if the EWG is an affiliate or associate company of the electric utility, unless each state commission with retail rate jurisdiction over the electric utility (or over an affiliate of the electric utility to whom the purchased power is re-sold) determines that the proposed sale would (1) benefit consumers; (2) not violate state law (including least-cost planning); (3) not provide the EWG with "any unfair competitive advantage"; and (4) be in the public interest.¹⁴ The state commission must also find that it has sufficient regulatory authority, resources, and access to books and records to make these determinations.¹⁵

The 1992 Act gives state commissions broad authority to review the books and records of (1) any electric utility subject to their jurisdiction; (2) any EWG selling power to such electric utility; and (3) any electric utility which is an affiliate of an EWG selling power to such electric utility.¹⁶ Trade secrets and sensitive commercial information are protected from public

10. *Id.* 15 U.S.C. § 79z-5a(c).

11. *Id.* § 79z-5a(c), (d)(2).

12. *Id.* § 79b(a)(11).

13. 16 U.S.C. § 824m (Supp. IV 1992).

14. 15 U.S.C. § 79z-5a(k).

15. *Id.*

16. *Id.*

disclosure.¹⁷

Although Title VII of the 1992 Act amends PUHCA, a statute which is administered by the SEC, the SEC will probably play a relatively limited role with regard to EWG regulation. The SEC will have oversight under section 32(h) over certain EWG-related activities undertaken by registered holding companies.¹⁸

A prospective EWG must file an application for determination of EWG status with the FERC.¹⁹ The FERC must act on the application within 60 days of receipt of an application.²⁰ An applicant filing in good faith will be deemed to be an EWG, entitled to the PUHCA exemptions, until the FERC acts on the application.²¹ EWG certification can be sought in advance of project construction and operation.²² The 1992 Act required FERC to promulgate rules within twelve months after enactment that would implement procedures for determining EWG status.²³

New PUHCA section 32(i) provides that an entity which would meet the definition of an EWG cannot rely for exemption from PUHCA upon an SEC declaratory order or staff no-action letter issued after the bill's enactment.²⁴ The intent of this provision is to force those who would be eligible for EWG status to obtain EWG certification from the FERC and comply with the new statutory and regulatory provisions governing EWGs, rather than pursuing the complex PUHCA-avoidance structures that have previously been utilized by independent power producers to avoid PUHCA. Projects which would not meet the "eligible facility" criteria for some reason can presumably still resort to SEC-approved ownership and control structures to avoid PUHCA regulation.

Another provision of the 1992 Act which potentially affects a broad scope of non-utility generators is section 712. Section 712 amends PURPA to mandate that state commissions undertake, within one year of enactment, an evaluation of (1) the impact of long-term wholesale power purchases on retail rates; (2) whether debt-heavy EWG capital structures threaten reliability or provide "unfair competitive advantage" to EWGs; (3) whether to adopt advance approval/disapproval of long-term power purchases; and (4) whether to require assurance of adequate fuel supply as a condition of power purchase approval.²⁵ Certain of these mandates, dealing with prudence of long-term purchases, may also affect qualifying facilities (QFs).

In addition to permitting EWGs located outside the U.S. to make retail sales, the 1992 Act adds a new section 33 to PUHCA which creates exemptions for a "foreign utility company" provided that approval is obtained from

17. *Id.*

18. *Id.* § 79z-5a(h).

19. *Id.* § 79z-5(a)(1).

20. *Id.*

21. *Id.*

22. *Id.* § 79z-5a(a)(2).

23. *Id.* § 79z-5a(a)(1).

24. *Id.* § 79z-5a(i).

25. 16 U.S.C.A. § 2621(d)(10)(A)(i)-(iv) (1993).

each state commission with jurisdiction over the retail electric (or gas) rates of a public utility company that is an associate or affiliate of the "foreign utility company" (other than an associate or affiliate of a registered holding company, for which SEC approval is required).²⁶ A "foreign utility company" is defined as a company that owns or operates facilities located outside the U.S. that are used for the generation, transmission or distribution of electric energy for sale or for retail distribution of natural or manufactured gas, if the company (1) derives no part of its income from the generation, transmission, or distribution of electric energy for sale or retail gas distribution within the U.S., and (2) neither it, nor any of its subsidiaries, is a public utility company operating in the U.S.²⁷

This provision provides greater opportunity for U.S. companies (including PUHCA holding companies) to invest in foreign generation. Under the former law, holding companies engaged in U.S. public utility activity were constrained from making foreign utility investments by the scope of the section 3 exemptions and the registered holding company "integration" standard. In addition, firms with no U.S. public utility operations were forced to seek an exemption under section 3(a)(5) holding company exemption if they engaged in foreign public utility activities; new section 33 permits such entities to invest in "foreign utility companies" without PUHCA jurisdictional consequences.

The 1992 Act also significantly amends sections 211 and 212 of the FPA to grant broad authority to the FERC to order transmission service.²⁸ Entities eligible for such relief have been broadened beyond electric power utilities and Federal power marketing agencies to include "any other person generating electric energy for sale for resale."²⁹ This language would include municipalities, independent power producers, EWGs and QFs. "Any transmitting utility," defined as any electric utility, qualifying cogeneration facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale," is subject to FERC transmission access orders.³⁰

Before applying for a transmission order, an applicant must first request service from the prospective transmitting utility at least 60 days before filing the application with the FERC. This request must include specific rates and charges, and other terms and conditions of transmission service.³¹ In order for the FERC to order transmission service, it must find that 1) the requested transmission would "be in the public interest";³² 2) the requested service would not unreasonably impair the reliability of affected utility systems;³³ 3) the requested service would not duplicate service already provided by contract

26. 15 U.S.C. § 79z-5b(a)(1), (2) (1988).

27. *Id.* § 79z-5b(a)(3).

28. 16 U.S.C.A. §§ 824j - 824k (1993).

29. *Id.* § 824j(a).

30. *Id.* § 796(23).

31. *Id.* § 824j(a).

32. *Id.* § 824j(a). This provision of section 211 does not state guidelines for determining what is "in the public interest," leaving broad discretion to the FERC.

33. *Id.* § 824j(b).

or tariff to the extent that such contract/tariff remains in effect;³⁴ 4) the service meets the standards set forth in section 212.³⁵ Amended section 211 no longer requires that the FERC determine that a transmission order “would reasonably preserve existing competitive relationships.”

An order permitting the transmitting utility to cease providing compulsory services may be issued by the Commission if it finds that 1) due to changed circumstances, requirements for such orders are no longer met; 2) the transmitting utility no longer has capacity in excess of that needed to serve its own customers; or 3) the ordered services require enlargement of transmission capacity and the transmitting utility cannot, with a good faith effort, obtain the necessary approvals or property rights.³⁶

Amended section 212 eliminates provisions which restricted the FERC's authority in this area and adds several new provisions. Section 212(a), as amended, sets forth broadly worded principles governing rates, terms and conditions of compulsory service provided subject to section 211 transmission orders. Rates for transmission service should permit recovery by the transmitting utility of all “costs incurred” in providing the requested service, including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs. These rates should promote the “economically efficient transmission and generation of electricity and shall be just and reasonable, and not unduly discriminatory or preferential.” Furthermore, these rates should ensure to the maximum extent possible that costs associated with and properly allocable to the service are recovered from the applicant and not from the transmitting utility's existing wholesale, retail or transmission customers. The revisions to section 212(e) explicitly add the provision that section 211 “shall not be construed to modify, impair, or supersede the antitrust laws.”³⁷

The 1992 Act adds new language to the FPA to bar the FERC from ordering retail wheeling directly to an end-user or to impose a retail wheeling condition, with certain “safe harbor” exceptions. This section provides that the Commission cannot issue an order, or impose a condition, requiring the transmission of electric energy directly to an ultimate consumer or to or for the benefit of an entity if such electric energy would be sold by such entity directly to an ultimate consumer unless the entity is, *inter alia*, a state or political subdivision of a state, a person having an obligation under state or local law to provide electric service to the public, or any corporation or association which is wholly-owned directly or indirectly by such an entity, *and* such entity was providing electric service to the ultimate consumer on the date of the enactment or would utilize transmission or distribution facilities that it owns or controls to deliver all such electric energy to such electric consumer.³⁸ This section does not disturb state or local authority to order retail wheeling.³⁹

34. *Id.* § 824j(c)(2).

35. *Id.* § 824k.

36. *Id.* § 824j(d)(1).

37. *Id.* § 824k(e).

38. *Id.* § 824k(h).

39. *Id.*

II. FERC IMPLEMENTATION OF EWG REGULATION

Almost immediately after the 1992 Act, the FERC received applications from independent power producers to be deemed EWGs. The FERC issued determinations of EWG status in *Commonwealth Atlantic Ltd. Partnership*,⁴⁰ *Doswell Ltd. Partnership*,⁴¹ and *Hartwell Energy Ltd. Partnership*.⁴²

On February 10, 1993, the FERC issued Order No. 550,⁴³ setting out filing requirements and procedures for EWG determinations. The FERC will publish notice in the *Federal Register* of EWG applications, and permit comments or interventions.⁴⁴ The FERC cautioned it would not consider issues outside the narrow focus of its determination under the 1992 Act, such as environmental challenges or objections to financing, or entertain requests for hearing on an application.⁴⁵ Copies of each EWG application will be served on the SEC, and on affected state commissions.⁴⁶ A filing fee will be required only for EWGs that will not otherwise be "public utilities" subject to the FERC's jurisdiction.⁴⁷ Like QF certifications, any material variation from the facts presented in an EWG application may render an EWG determination invalid.⁴⁸ The FERC Secretary will issue notice of EWG determinations, and notify directly the applicant, intervenors and the SEC.⁴⁹ Section 365.3(a)(2)(iii) of the new EWG rules requires an applicant to disclose "any electric utility company that is an affiliate company or associate company of the applicant," even where affiliate transactions are not in issue.⁵⁰ Similarly, section 365.3(a)(2)(ii) requires an EWG applicant to describe any lease arrangements involving the eligible facility and a public utility company.⁵¹ In contrast to its QF practice, the FERC will not issue deficiency letters to EWG applicants; it will grant or deny the application within 60 days of receipt.⁵² The FERC also clarified that its "ministerial" role does not require preparation of environmental assessments or impact statements in connection with EWG determinations.⁵³

The FERC originally concluded that an operator of a project that was not itself a seller of power was not an EWG.⁵⁴ Similarly, the FERC initially ruled that an owner lessor of an eligible facility must also sell electric energy at wholesale to be an EWG.⁵⁵ On rehearing, in Order No. 550-A issued April

40. 61 F.E.R.C. ¶ 61,270 (1992).

41. 61 F.E.R.C. ¶ 61,325 (1992).

42. 61 F.E.R.C. ¶ 61,283 (1992).

43. 58 Fed. Reg. 8897 (1993) (to be codified at 8 C.F.R. pt. 365, 381).

44. 18 C.F.R. § 365.3 (1993); see 18 C.F.R. §§ 385.211, 385.214.

45. 58 Fed. Reg. 8906.

46. 18 C.F.R. § 365.3(a) (1993).

47. *Id.* § 381.801.

48. *Id.* § 365.7.

49. *Id.* §§ 365.5, 365.6.

50. 18 C.F.R. § 365.3(a)(2)(iii).

51. *Id.* § 365.3(a)(2)(ii).

52. *Id.* § 365.5.

53. 58 Fed. Reg. 8897.

54. *KFM Pepperell, Inc.*, 62 F.E.R.C. ¶ 61,182 (1993).

55. *InterAmerican Energy Leasing Co.*, 62 F.E.R.C. ¶ 61,283 (1993).

14, 1993,⁵⁶ the FERC reversed itself and declared it would award EWG status to facility operators and to passive owners. In interpreting the 1992 Act, the FERC recognized that “passive” leaseholds are “typical” in the financing of non-utility generators, and reasoned that Congress would not have intended to deny exemption from PUHCA to passive investors.⁵⁷ The FERC clarified that a “lease” interest in an eligible facility would be treated as a wholesale sale of electric energy at wholesale for purposes of section 32 (a)(1), absent a case-specific showing of harm to the public interest.⁵⁸ In addition, the FERC held that an “operator” of an eligible facility should be deemed to be making sales at wholesale if it has an agency relationship with the owner/seller and is subject to the direction of the seller, absent a specific showing of harm to the public interest.⁵⁹ As Congress’ intent in section 32(i) was to prevent forum shopping, the FERC reasoned that operators should not be deprived of their pre-existing opportunity to obtain exemption from PUHCA from the SEC.

On rehearing, the FERC acknowledged that a “critical objective” of EWG determinations is “regulatory certainty if EWGs are to play a significant role in meeting the nation’s electric power needs.”⁶⁰ Objections or concerns about an EWG application must, therefore, be raised in the comment period. The FERC reserved the option to challenge the standing of appellants who raise an issue for the first time on appeal.⁶¹ The FERC commented, further, that it would not actively monitor the status of an EWG, noting the SEC’s enforcement authority under PUHCA. The duty of the EWG “in the first instance . . . [was] to be vigilant to ensure that it continues to qualify to be an EWG.”⁶²

In specific EWG determinations,⁶³ the FERC has held that a person otherwise meeting the requirements of an EWG may also sell byproducts of generation, including steam and fly ash, and not violate the “exclusivity” mandate in new section 32 of PUHCA. The FERC has held that a QF can also be an EWG.⁶⁴ In *Louis Dreyfus Electric Power*,⁶⁵ the FERC denied EWG status to a power marketer which had no *physical* facilities for power generation or transmission. In its denial, the FERC noted that the SEC had not yet ruled whether under PUHCA contracts for the sale or transmission of electricity were “facilities.” In *Southern Electric Wholesale Generators*,⁶⁶ the FERC held that indirect ownership and/or operation of an eligible facility must be through an “affiliate,” as defined in section 2(a)(11)(B) of PUHCA. In *Cos-*

56. 58 Fed. Reg. 21,250 (1993) (to be codified at 18 C.F.R. pt. 365).

57. *Id.*

58. *Id.* at 21,254.

59. *Id.*

60. *Id.* at 21,251.

61. *Id.*

62. *Id.* at 21,252.

63. *Richmond Power Enter., L.P.*, 62 F.E.R.C. ¶ 61,157 (1993); *Elm Energy & Recycling (UK) Ltd.*, 63 F.E.R.C. ¶ 61,201 (1993).

64. *Richmond Power*, 62 F.E.R.C. ¶ 61,157, at 62,098 (1993).

65. 62 F.E.R.C. ¶ 61,234 (1993).

66. 63 F.E.R.C. ¶ 61,050 (1993). The FERC denied the application in *Southern Electric*, in part, as to some applicants because it was not clear from the representations or the facts in the application that certain of the applicants were affiliates within the meaning of PUHCA.

tanera Power Corp.,⁶⁷ the FERC clarified that a separate EWG application must be filed by each person wishing to be treated as an EWG.

III. FERC RULEMAKING ON PURPA REGULATIONS

On November 16, 1992, the FERC issued a Notice of Proposed Rulemaking, titled "*Streamlining of Regulations Pertaining to Parts II and III of the Federal Power Act and the Public Utility Regulatory Policies Act of 1978*" (NOPR).⁶⁸

Some of the proposed changes in the NOPR are similar to those proposed by the FERC in 1988 in the so-called "ADFAC NOPR" (regarding administrative determination of full avoided costs, sales of power to QFs, and interconnection facilities), and the "Fourth NOPR" (regarding streamlining of QF certification procedures and clarifying and codifying QF technical criteria). The FERC implies in the new NOPR that it has abandoned the other changes addressed in the 1988 NOPRs because conditions which directly or indirectly affect QFs have changed in the interim. In this regard, the FERC cites passage of the Solar, Wind, Waste and Geothermal Power Production Incentives Act of 1990⁶⁹ (which removed size restrictions on certain small power producers), the FERC's acceptance of market-based rates in certain circumstances for independent power producers, affiliated power producers, and traditional public utilities, and FERC orders concerning QF access to transmission.

A. Procedural Modifications and Revised Definitions

The Commission has proposed to revise its PURPA regulations by:

1. Encouraging greater use of the QF self-certification notice option. The FERC has proposed that such notices be in the form of an affidavit in an attempt to make such notices more readily accepted by lending institutions providing project financing.⁷⁰
2. Reducing the burden on facilities which have been formally certified as QFs which subsequently seek recertification due to minor changes to the facilities. The Commission proposes "pre-authorized" recertification if the changes to the facilities fall within a specified group of changes, including (but not limited to) a location change; a change in primary energy source to a specified waste energy source; a change in the primary energy source of a cogenerator if the new fuel doesn't result in an increase in use of gas or oil; a change in the maximum net power production capacity of a small power producer; a change in the maximum net power production capacity of a cogenerator if the operating and efficiency values remain at or above previously certified values.⁷¹

67. 61 F.E.R.C. ¶ 61,335 (1992).

68. 57 Fed. Reg. 55,176 (1992), *errata issued* 57 Fed. Reg. 58,168 (1992).

69. Pub. L. No. 101-575, 104 Stat. 2834 (codified as amended in scattered sections of 16 U.S.C. and 42 U.S.C.).

70. 57 Fed. Reg. 55,192-94 (1992).

71. *Id.* at 55,193.

3. Clarifying that the 90-day time period for Commission action on a QF certification application does not begin until all information needed to complete the application has been submitted and the filing fee has been paid. No deadline exists for a staff determination on whether an application is complete.⁷²
4. Amending certain definitions to clarify that QFs may include transmission lines, step-up transformers, and switchyard equipment under certain circumstances.⁷³
5. Adding a new provision to make clear that the "power production capacity" of a facility is the maximum net output of the facility which can be safely and reliably achieved under the most favorable operating conditions likely to occur over a period of several years.⁷⁴
6. Clarifying that the electric power production capacity of a facility should be measured at the point of interconnection with the purchasing utility's transmission system.⁷⁵
7. Setting forth more explicitly the information required in QF certification applications, and including a new standardized application form (FERC Form 556), ostensibly to make it easier and less expensive to apply for certification, and to reduce processing delays.⁷⁶

B. Proposed Technical Modifications

The Commission has proposed to modify its PURPA regulations by:

1. Including a list of fuels which will automatically be considered "waste" fuels, such as certain types of: anthracite culm; anthracite coal refuse; bituminous coal refuse (such as gob, cleaning plant tailings, bone or bone coal, filter cake, screen refuse, pond coal), subbituminous coal, coal refuse, lignite, gaseous fuels (such as refinery gases, coke oven gas, blast gas, carbon black gas, coal mine gas, and "waste natural gas"), petroleum coke, residual heat, exothermic reactions, rubber tires, and government certified disposal materials.⁷⁷
2. Revising the definition of "waste" to eliminate requirement that waste be a "by product." "Waste" would now mean "an energy source other than biomass that has essentially no commercial value."⁷⁸
3. Requiring use of a 12 consecutive month period, beginning on the date a QF first produces electric energy, for purposes of determining whether a QF meets the FERC's technical standards, rather than use of a calendar year.⁷⁹
4. Modifying the definition of "topping-cycle" cogeneration facility and "useful thermal energy output" to clarify that only some of the reject

72. *Id.*

73. *Id.* at 55,192.

74. *Id.*

75. *Id.*

76. *Id.* at 55,193.

77. *Id.* at 55,192.

78. *Id.*

79. *Id.*

heat from power production must be used for useful thermal purposes, and that thermal energy need not be from every turbine, but only somewhere along turbines linked by a sequential energy flow.⁸⁰ This would codify *Texas Industries*⁸¹ with respect to the "sequential use" requirement.

5. Making clear that small power producers using solar, wind, waste, and geothermal energy as the primary energy source are not subject to the 80 MW size limit on small power producers.⁸²

In addition to changes to the PURPA regulations directly affecting QFs, the FERC proposed changes to certain other of its regulations implementing the Federal Power Act and PURPA. In particular, the FERC proposed to make independent power producers and affiliated power producers subject to the annual charges applicable to public utilities under 18 C.F.R. § 382.

IV. FERC TREATMENT OF TRANSMISSION ACCESS FOR NON UTILITY GENERATORS

In decisions predating the 1992 Act, the FERC maintained that QFs were not entitled to mandatory transmission access, absent the QFs waiver of their right under PURPA to avoided cost rates. The Commission believed that the inclusion of QFs in other portions of the FPA while they were absent from the list of entities eligible to request mandatory wheeling in section 211 conclusively indicated that Congress did not intend for QFs to benefit from the compulsory transmission access provision absent willingness by the QF to become, in effect, an "electric utility" by waiving its entitlement under PURPA to sell electric energy at avoided cost rates.⁸³

Based upon the 1992 Act the FERC reversed course and relied upon the broad authority of section 211, as amended, to order electric utilities to provide QFs with access to transmission services at cost-based rates, rejecting the notion that QFs concomitantly waive their rights to avoided cost rates.⁸⁴

V. REGIONAL TRANSMISSION

On November 10, 1992, the FERC issued a request for comments regarding "Regional Transmission Groups". An RTG would be a voluntarily created groups of utilities, NUGs and other wholesale suppliers to implement "open" transmission access on a regional basis.⁸⁵

80. *Id.*

81. *Texas Indrus. Inc.*, 29 F.E.R.C. ¶ 61,051 (1984).

82. *Id.*

83. See *Utah Power & Light Co.*, 59 F.E.R.C. ¶ 61,035, at 61,114. In *Environmental Action v. FERC*, 939 F.2d 1057 (D.C. Cir 1991), the court remanded the issue of the Commission's exclusion of QFs from access to mandatory transmission service. This resulted in the Commission's Order on Remand (57 F.E.R.C. ¶ 61,363 (1991)) and an Order Denying Rehearing on Late-Filed Interventions and on QF Access Issue (59 F.E.R.C. ¶ 61,035 (1992)).

84. See, e.g., *Entergy Serv. Inc.*, 63 F.E.R.C. ¶ 61,156, at 61,993 (1993).

85. 57 Fed. Reg. 54,580 (1992).

VI. FERC AND JUDICIAL DECISIONS AFFECTING NON-UTILITY GENERATORS

A. FPA Rate Review.

In *Northern Electric Power Co., L.P.*,⁸⁶ the Commission rejected an initial rate filed by Northern Electric for the sale to Niagara Mohawk of power to be produced by the 36.1 MW Hudson Falls Hydroelectric Project, which is expected to be a QF. Qualifying small power production facilities of 30-80 MW are not exempt from the Federal Power Act, and therefore must file their rates with FERC. The rate, which is less than the utility's 1990 long run avoided cost as approved by the New York Public Service Commission, had been agreed to by the parties and was apparently related to settlement of several long-standing disputes between the utility and Northern's predecessor. In denying approval of the rate, the FERC pointed out that rates for sale by QFs subject to its jurisdiction must be no more than the purchasing utility's avoided costs, as required by PURPA, and it is its long standing policy to rely on "avoided cost rates established by state commissions to determine that rates of jurisdictional QFs . . . are just and reasonable under the FPA."⁸⁷ Because the PSC had withdrawn the avoided costs upon which the agreed-upon rates in this case relied, the rates could not be found just and reasonable.⁸⁸

In *Western Massachusetts Electric Co.*,⁸⁹ the FERC held that interconnection charges billed by jurisdictional public utilities to QFs are subject to review under sections 205 and 206 of the FPA to the extent that some or all of the output of the QF is being transmitted to another purchasing entity.

B. Intervention in State Implementation.

In *Industrial Cogenerators v. Florida Public Service Commission*,⁹⁰ the FERC issued an order clarifying, vacating in part, and refusing rehearing of its order of June 27, 1988.⁹¹ The Industrial Cogenerators had complained of a Florida PSC decision, issued in 1987, establishing rates to be charged QFs for standby services. In the 1988 order, the FERC had determined that (1) its regulations require separate rates "as between maintenance and backup power absent a factual demonstration that there is no cost difference between supplying power for the two services," (2) that a QF may not be charged "a different rate than it would otherwise be entitled to if it were not a self-generating customer" absent an adequate showing, and (3) that imposition of a ratchet that discriminated against QFs was unlawful.⁹²

In regard to whether the rates approved by the Florida PSC violated the FERC's standards, the FERC said these matters were factual and to be

86. 61 F.E.R.C. ¶ 61,188 (1992).

87. 61 F.E.R.C. ¶ 61,188, at 61,701 (1992).

88. *Id.*

89. 61 F.E.R.C. ¶ 61,182 (1992).

90. 61 F.E.R.C. ¶ 61,202 (1992).

91. 43 F.E.R.C. ¶ 61,545 (1988).

92. *Id.* at 62,353-54.

decided by the "appropriate state forum." The FERC noted that subsequent to its order the Florida Supreme Court had upheld the PSC and that in 1991 the PSC had amended its rules on the issue of rates for non-firm standby and supplemental service. Because these events mooted the disputes addressed in the FERC's order, the Commission vacated the portions of its 1988 order interpreting PURPA.⁹³

In another matter of long standing, in *Cogeneration Coalition of America, Inc.*,⁹⁴ the FERC denied a petition, filed in 1987, that had asked the Commission to institute a nationwide investigation into "state regulatory practices which allegedly discourage cogeneration." In particular, the Coalition had alleged that state commission approval of cogeneration deferral rates or other contracts/tariffs that provide incentives to ratepayers to take power from the utility rather than install on-site cogeneration facilities have an anticompetitive effect on the QF industry. The Commission acknowledged that it has non-exclusive jurisdiction to enforce the QF regulations, but pointed to the state courts as the more appropriate forum for addressing the Coalition's specific concerns.⁹⁵ It also noted that states have wide latitude to implement the QF regulations as they deem appropriate and that the alleged anticompetitive actions concern retail rates, which are regulated at the state level.⁹⁶

C. *Waivers of PURPA Regulations*

1. *Fuel Use by Small Power Producers*

In *Kramer Junction Co.*,⁹⁷ the Commission granted solar powered QFs a temporary waiver of the 25 percent limitation on fossil-fuel use by small power production facilities in order to allow the QFs to increase their use of natural gas-fired generation to produce more power than would have been possible using available sunlight during a 120 day period in 1992. The QFs argued that the available sunlight during 1992 had been unforeseeably below normal levels because the eruption of the Mt. Pinatubo volcano caused an increase level of cloud cover over California, where the facilities are located. In granting the waiver (which the purchasing utility Southern California Edison opposed), the Commission reasoned that it had previously granted waivers for limited time periods during periods of unusual operation, (i.e., testing, start-up and the introduction of novel technologies).⁹⁸ Granting the waiver would encourage the application of novel technologies, whereas denial "would send the wrong signal to potential developers of facilities powered by solar resources."⁹⁹

2. *Operating and Efficiency Standards for Cogenerators*

The FERC began to standardize its criteria for granting cogenerators a temporary waiver of the operating and efficiency standards during initial star-

93. 61 F.E.R.C. ¶ 61,202, at 61,754.

94. 61 F.E.R.C. ¶ 61,252 (1992).

95. *Id.* at 61,926.

96. *Id.* at 61,927.

97. 61 F.E.R.C. ¶ 61,309 (1992).

98. *Id.* at 62,160.

99. *Id.*

tup and testing.¹⁰⁰ The FERC granted the waivers in these decisions on public interest grounds, citing to such factors as the limited duration of the waiver request, the fact that noncompliance was during testing and therefore further waiver would be unnecessary and that waiver would fulfill PURPA's goal of encouraging cogeneration.¹⁰¹

D. Useful Thermal Output — Independent Business Purpose Test

In *Bonneville-Yuma Corp.*,¹⁰² the FERC examined whether an affiliated greenhouse met the "useful thermal output" requirement for a qualifying cogeneration facility. The FERC required the applicant to provide economic support for the selling price of the greenhouse produce and the cost of thermal and electrical energy supplied to the greenhouse. As the analysis included "reasonable escalation factors," and showed a reasonable return, on a net present value basis, after expenses and return of capital investment in the affiliate greenhouse, the FERC found that the "useful thermal output" requirement was satisfied.¹⁰³ In another decision, the FERC announced that where an economic analysis involves future projections of revenues and expenses, the *actual* profitability of the thermal enterprise will determine whether the facility remains a QF.¹⁰⁴

In 1992, carbon dioxide (CO₂) production achieved FERC recognition as a "presumptively useful" thermal application of cogenerated steam. The Commission rejected opposition by a producer of CO₂ and other industrial gases that the carbon dioxide production plants served by Polk Power Partners, Lavair Cogeneration Limited Partnership, and AES WR Limited Partnership were not employing a "useful" process.¹⁰⁵ Intervenor argued that these CO₂ plants used a process that was so costly and inefficient that it failed to satisfy the "independent business purpose" test. The Commission held that it:

[a]pplies one of three economic tests in determining whether a thermal output is useful. The initial inquiry is whether the use of a facility's thermal output is common; if so, it is considered presumptively useful. Only if the Commission finds that the use of the thermal output is not common, i.e., the use involves a new technology or a use not previously proven to be economically justified, will [it] analyze the economics of the thermal use.¹⁰⁶

Noting it had certified fourteen QFs with CO₂ steam hosts, the FERC concluded CO₂ production was a common industrial use and, accordingly, the FERC would not investigate the economics of these facilities' thermal uses.¹⁰⁷

100. See, e.g., *O.L.S. Energy Agnews, Inc.*, 61 F.E.R.C. ¶ 61,293 (1992); *KES Kingsburg, L.P.*, 59 F.E.R.C. ¶ 62,279 (1992); *Hadson Power 12-Altavista*, 59 F.E.R.C. ¶ 62,167 (1992).

101. *KES Kingsburg L.P.*, 59 F.E.R.C. at 63,618.

102. 58 F.E.R.C. ¶ 62,059 (1992).

103. *Id.* at 63,113.

104. *AESCB Ltd. Partnership*, 58 F.E.R.C. ¶ 62,253 (1992).

105. *Polk Power Partners L.P.*, 61 F.E.R.C. ¶ 61,300 (1992), *appeal sub nom. Liquid Carbonic Indus. Corp. v. FERC*, No. 93-1095 (D.C. Cir. filed Jan. 29, 1993).

106. 61 F.E.R.C. ¶ 61,300, at 62,127 n. 5, *citing La Jet Energy Co.*, 44 F.E.R.C. ¶ 61,070 (1988).

107. 61 F.E.R.C. ¶ 61,300, at 62,128. The FERC issued its last decision requiring a cogeneration

E. QF Certification

In *Sugarloaf Citizens Assoc. v. FERC*, 959 F.2d 508 (4th Cir. 1992), the court affirmed the FERC's decision not to expand the narrow scope of a QF certification proceeding by considering the environmental impact of a facility. The court characterized as "well supported" the FERC's position that QF certification is "merely a ministerial act which presents no opportunity for consideration of any environmental impact."¹⁰⁸ In *Cogentrix of Mayaguez, Inc.*,¹⁰⁹ the FERC certified a cogeneration facility over the objections of intervenors who contested inter alia, the need for the capacity, the environmental impacts on land, air and water, and the level of electric rates; argued that prohibitions on use of coal existed under Puerto Rico law; and cited a lack of evidence of commitments for the steam production of the facility. The FERC reminded intervenors that because certification proceedings are narrow in scope the bulk of issues were outside its scope. With regard to coal, the FERC noted no prohibition in PURPA or its own regulations to its use in qualifying cogeneration facilities. Finally, whether the facility satisfies the "useful thermal output" requirement depends upon the facts at and after the time the facility first produces electric energy.¹¹⁰ The FERC rejected similar intervenor challenges to certification of the 1034 MW Sithe/Independence facility.¹¹¹

F. Utility Ownership

In several decisions the FERC certified QFs where the existing ownership exceeded the 50% equity interest limitation on ownership by an electric utility. In *Gordonsville Energy, L.P.—Unit I*,¹¹² the limited partnership consisted solely of wholly-owned subsidiaries of an electric utility holding company. The combined 100% ownership interest in Gordonsville by an electric utility holding company clearly failed to satisfy the ownership requirements.¹¹³ The FERC certified the facility based upon the owner's explanation of how, the upstream ownership of the facility would be adjusted, as of the date the facility first produces electrical energy, to reduce the utility interests to 25%, representations that the new partner would not be directly or indirectly engaged in generation or sale of electric power other than from QFs or own or operate electric facilities other than QFs, and discussion of how any future affiliate service agreements and loans would be negotiated.¹¹⁴

In *Scrubgrass Generating Co., L.P.*,¹¹⁵ the FERC approved a "true-up"

facility to submit an economic analysis to justify an affiliated carbon dioxide (CO₂) production plant as useful thermal output in *AES CB Ltd. Partnership*, 58 F.E.R.C. ¶ 62,253 (1992).

108. 959 F.2d at 513.

109. 59 F.E.R.C. ¶ 61,159, *reh'g denied*, 59 F.E.R.C. ¶ 61,392 (1992).

110. 59 F.E.R.C. at 61,589.

111. *Sithe/Independence Power Partners, L.P.*, 61 F.E.R.C. ¶ 61,212 (1992).

112. 60 F.E.R.C. ¶ 62,137 (1992).

113. 18 C.F.R. § 292.206 (1993).

114. 60 F.E.R.C. ¶ 61,237, at 63,353. The FERC certified an identical ownership structure in *Gordonsville Energy, L.P. Unit II*, 60 F.E.R.C. ¶ 62,136 (1992). See *Keystone Energy Serv. Co., L.P.*, 58 F.E.R.C. ¶ 62,235 (1992); *Crockett Cogeneration*, 60 F.E.R.C. ¶ 62,258 (1992).

115. 61 F.E.R.C. ¶ 62,215 (1992).

procedure designed to address a potential circumstance where the partner affiliated with an electric utility would have to acquire the ownership interest of one of the non-utility partners, after the facility first produced electric power. If the utility affiliate was unable immediately to resell that interest to a nonutility, the utility's share of the stream of benefits would exceed the equity percentage limitation in section 292.206. Under the "true-up" the utility affiliate would reduce its share of the stream of benefits so that it would not at any point in the facility's life receive more than 50% of the stream of benefits, on a net present value basis.

VII. REGIONAL DEVELOPMENTS

A. Massachusetts

On August 20, 1992 the Massachusetts Supreme Court overruled an order of the Energy Facility Siting Council approving the siting of a coal fired cogeneration facility.¹¹⁶ The Council's order was overturned because it did not contain the findings required by the siting statute¹¹⁷ that the energy to be supplied by the facility was necessary, produced minimum environmental impact and lowest cost.¹¹⁸

Effective September 1, 1992, the Energy Facilities Siting Council was merged into the Department of Public Utilities.¹¹⁹ Under the reorganization, proposals to construct facilities will be reviewed and decided by a newly created Energy Facilities Siting Board.¹²⁰ The Board has begun a comprehensive review of the existing siting laws¹²¹ in light of standards established in the *City of New Bedford* case and the Public Utilities Commission's Integrated Resource Management (IRM) regulations.¹²² Under the IRM regulations each utility is required to adopt a ranking system to evaluate projects on the basis of reliability and cost. More specifically, the ranking systems are required to evaluate the projects on the basis of (1) price, (2) quality of output or savings, (3) timing of the output or savings, (4) project feasibility, (5) fuel diversity, and (6) environmental externalities.¹²³ At present it appears to be possible that a project with the highest score in the IRM selection process might not be able to meet the standards of the siting statute that require the project be necessary, produce minimum environmental impact and supply energy at the lowest cost.

On November 10, 1992 the Public Utilities Commission issued its decision¹²⁴ on the value to be assigned to externalities for purpose of evaluating alternative supply sources under the Integrated Resource Management regula-

116. *City of New Bedford v. Energy Facilities Siting Council*, 597 N.E.2d 1032 (1992).

117. Mass. Gen. Laws Ann. ch. 164, § 69H (West 1976 & Supp. 1993).

118. 597 N.E.2d at 1035.

119. Mass. Gen. Laws Ann. ch. 164 § 69H (Supp. 1993).

120. *Id.* at § 69H(2).

121. *Northeast Power Report*, November 13, 1992, at 12.

122. D.P.U. 89-239 (August 31, 1990).

123. Mass. Regs. Code tit. 220, § 10.3(6)(d)(3) (1991).

124. D.P.U. 91-131 (November 10, 1992).

tions adopted in 1990.¹²⁵ The decision retained the same externality value, adjusted for inflation, adopted by the Commission in 1990.¹²⁶

B. New York

A proceeding before the New York State Public Service Commission (NY PSC or Commission) focuses on the conditions under which a utility may curtail its purchases of power from QFs. FERC regulations provide that a utility is not required to purchase QF power during any period in which, due to operational circumstances, such purchases will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself (often referred to as "negative avoided costs.")¹²⁷ As described by the NY PSC:

Under § 292.304(f), operational circumstances exist, for example, when a utility would be forced to shut off one of its own "must-run" units during a light-load period in order to take generation from QFs. Once shut down, such a utility unit would not be available to generate when load rises away from the light-load point toward the next load peak.¹²⁸

Prior to implementing operational circumstances curtailments, the utility is required to provide notice to potentially affected QFs in accordance with applicable state law.¹²⁹

The NY PSC examined this issue in 1989, after New York State utilities began to include in their contracts with QFs clauses that explicitly reserved their right to implement operational circumstances curtailments. The NY PSC, however, determined that based on then-current forecasts of QF penetration, utility capacity and customer demand, the need for operational circumstances curtailments was unlikely to materialize. It permitted utilities to include in their contracts language that reserved their PURPA curtailment rights, but ordered the utilities not to implement curtailments without explicit NY PSC authorization to do so.¹³⁰ Among other things, the Commission noted that the New York State utilities operated as part of an integrated system, the New York Power Pool (NYPP) and held that "before any utility can be allowed to curtail, it must be shown that NYPP cannot absorb the electricity."¹³¹

In August, 1992, Niagara Mohawk Power Corporation filed a petition asking the Commission to reopen for consideration the need for curtailments. In its petition, Niagara Mohawk argued that expected levels of QF penetration had changed since the time of the 1989 curtailment orders. Niagara Mohawk claimed that as a result of current QF obligations, it has already been forced to

125. D.P.U. 89-239 (August 31, 1990).

126. *Id.*

127. 18 C.F.R. § 292.304(f) (1993).

128. *Order Reopening Proceeding*, Cases 92-E-0814, 88-E-081 (NY Pub. Service Comm. Oct. 2, 1992) at 2.

129. 18 C.F.R. § 292.304(f) (1993).

130. *Order Rejecting Contract Curtailment Clauses*, Case 88-E-081, (N.Y. Pub. Service Comm'n. June 27, 1989), *reh'g denied Order Denying Rehearing and Clarifying Prior Order* (N.Y. Pub. Service Comm'n. Dec. 12, 1989).

131. *Order Rejecting Contract Curtailment Clauses* at 16.

choose between shutting down its own units to accept QF power and selling excess power to the NYPP. It claimed that sales of excess QF power to the NYPP are made at a loss to the utility, which is the equivalent of incurring "negative avoided costs." Niagara Mohawk further stated that the recent legislative repeal of the six cent rate (as to future contracts) "marks a change in . . . public policy . . . [that] now requires the Commission to take full account of the justice and reasonableness of [QF] rates . . . , and to assure the efficient use of [QF] power".¹³²

On October 2, 1992, the Commission issued an order determining that further review of curtailment issues was warranted and setting the matter for hearing before an administrative law judge.¹³³ It reopened for consideration the issue of whether the need for curtailments should be assessed on a utility-stand alone basis or on a pool-wide basis and invited comments on a wide range of sub-issues including the methodology for determining when "operational circumstances" exist; exclusions of certain QFs from curtailment; and the order in which QFs should be curtailed if curtailment is deemed necessary. It also ordered other New York State major utilities to participate in the case. Subsequently, Consolidated Edison Company and New York State Gas & Electric Corporation (NYSEG) submitted petitions requesting authority to implement operational circumstances curtailments, although NYSEG later withdrew its petition, choosing instead to resolve its excess generation problem through individual negotiations with its QFs.

The case has raised concerns among QF developers and lenders on issues such as whether operational circumstances curtailments can be implemented where a contract does not explicitly provide for such curtailment, and the use of operational circumstances curtailments as a methodology for the utility to reduce its total cost of QF purchases, for example, by implementing curtailments on the basis of contract price. Similarly, gas suppliers are concerned about the effect of curtailment on existing contracts with the many gas-fired QF projects in New York.

C. Pennsylvania

In 1992, the long-dormant generic investigation into whether changes were warranted to Pennsylvania's regulations implementing PURPA came to life in response to a utility petition requesting the Commission complete the proceedings.¹³⁴ After soliciting comments to update the record which had last been supplemented in 1987, the Administrative Law Judge on December 31, 1992 issued a lengthy decision in which he recommended incremental changes to the regulations and improved coordination with resource planning in lieu of the sweeping changes urged principally by the electric utilities. A Commission decision is expected in the summer of 1993.

Litigation continues over several power sales contracts signed in 1987

132. *Order Reopening Proceeding* at 5-6, (quoting Niagara Mohawk petition at 4).

133. *Order Reopening Proceeding*.

134. Investigation upon the Commission's own motion into the regulations at 52 Pa. Code § 57.31, Docket No. I-860025.

with West Penn Power Company. On May 22, 1992, the Commission, on remand from the Commonwealth Court, recalculated the capacity cost credit in the electric energy purchase agreement between West Penn Power Corporation and Mon Valley Energy Corporation. The Commission used tax rates in existence as of the date the agreement was signed October 15, 1987 in lieu of tax rates in effect at the time the parties were in "serious negotiations." Appeals were filed by West Penn and by two of its largest industrial customers. On March 10, 1993, the Commonwealth Court vacated and remanded the decision to the Commission to recalculate the capacity credit as of October 15, 1987, but with changes to *all* inputs. *Armco Advanced Materials v. Pennsylvania P.U.C.*¹³⁵

In *West Penn Power Co. v. Pennsylvania P.U.C.*,¹³⁶ the Commonwealth Court affirmed 4-3 the Commission's January 14, 1992 decision which extended the milestone dates in the agreement between Mon Valley Energy Corporation and West Penn Power Company to prevent termination of the contract due to litigation delays. The court held that the Commission had jurisdiction to maintain the status quo. The Court also ruled that the threat to economic loss supported issuance of an emergency order to stay the good faith deposit due dates and that the Commission has authority under PURPA to order modifications of EEPA contracts submitted to the Commission for its approval. The dissent argues that when the Commission is asked to modify an EEPA, it is obligated by PURPA to determine if the revisions are in the public interest. The Commission erred in not permitting West Penn to show that power from the Mon Valley project was no longer needed and would result in excessive charges to ratepayers.

Appeals are pending in *Armco Advanced Materials Corp. and Allegheny Ludlum Corp. v. Pennsylvania P.U.C.*,¹³⁷ and *West Penn Power Co. v. Pennsylvania P.U.C.*,¹³⁸ of a Commission order.¹³⁹ The Commission's order was issued on remand and recalculated the capacity cost credit in the agreement between West Penn Power Company and North Branch Energy Partners by using inputs in existence at the time the agreement was signed instead of those in existence as of the time of serious negotiations between the contracting parties. Parties allege that the Commission's order improperly implemented the remand order by recalculating avoided costs as of the original contract signing date by using some avoided costs inputs from the contract signing date and some avoided cost inputs from a prior period, and that the Commission should have considered West Penn's current capacity needs.

On July 9, 1992,¹⁴⁰ the Commission entered an Order granting Metropolitan Edison Company's (Met Ed) petition for approval of the notice Met Ed

135. No. 1147, 1148 (C.D. 1992).

136. 615 A.2d 951 (1992) (petitions for allowance pending).

137. No. 2742 (C.D. 1992).

138. No. 2755 (C.D. 1992).

139. No. P-880284 (Nov. 24, 1992).

140. *Petition of Metropolitan Edison Company Requesting Approval of the Form, Manner, and Timing of Notice to Customers of the Filing of a Petition for Approval of Rate Recovery Re: York County Energy Partners L.P.*, No. P-920579.

will send, via bill insert, to its customers concerning Met Ed's filing of a petition requesting the Commission's approval of rate recovery for the costs proposed to be paid under Met Ed's agreement with York County Energy Partners, L.P. (YCEP). The Commission stated that because the form of such notices has "evolved into a relatively standardized format," utilities no longer must obtain Commission orders approving the form or the manner of notice.

In an Order entered September 30, 1992,¹⁴¹ the Commission granted P.H. Glatfelter Company's (Glatfelter) petition for declaratory order, holding that the power purchase agreement for the sale of electric energy entered into between Glatfelter and Metropolitan Edison Company (Met Ed) in 1986 entitled Glatfelter to sell, and obligates Met Ed to purchase, all electric energy made available from the original Glatfelter Facility. Glatfelter represented that to comply with environmental requirements it must install a new boiler at the Facility to replace two older units. The new boiler will increase Glatfelter's internal electrical requirements making it impossible for Glatfelter to satisfy the minimum delivery requirement contained in the Agreement, thereby subjecting Glatfelter to penalty provisions. Glatfelter proposes to install a new turbine generator to meet its internal electrical load, thereby freeing up enough energy to meet the minimum delivery obligation to Met Ed. Because a portion of its internal electrical load will be met by the operation of the new turbine, Glatfelter will have additional energy available from the facility's original five units for sale to Met Ed. Met Ed refused to purchase the additional energy. The Commission concluded that a plain reading of the Agreement entitled Glatfelter to sell the additional energy to Met Ed, consistent with the FERC and Commission regulations which state that a QF is entitled to sell all of its electrical output to a utility.

The Commission noted that generally it will grant modifications to a QF-utility contract "sparingly and reluctantly" unless both parties agree to the modifications, and only in certain circumstances — at the request of one of the parties, if "necessary to allow the continuance of the arrangement" between the QF and the utility, and if substantive in nature, when the modification is "essential and . . . consistent with the requirements and intent of PURPA and implementing regulations."

In *Pennsylvania Electric Co. v. Pennsylvania P.U.C.*,¹⁴² Pennsylvania Electric Company (Penelec) has filed a petition for review with the Commonwealth Court of the Commission order entered November 17, 1992 which inter alia, directed Penelec to enter into two Power Purchase Agreements (PPAs), each 80 megawatts of electric generating capacity. Penelec alleges that the Commission lacks the authority to require it to enter into a PPA with any of the qualifying facility developers. Penelec also alleges that the order is not supported by substantial evidence and is arbitrary and capricious. In *Cambria Partners v. Pennsylvania P.U.C.*,¹⁴³ a third QF has filed a petition for

141. *Petition of P.H. Glatfelter Company for Declaratory Order Re: Power Purchase Agreement Between Metropolitan Edison Company and P.H. Glatfelter Company*, No. P-920584.

142. No. 2700 (C.D. 1992).

143. No. 2719 (C.D. 1992).

review in which it alleges that the order is arbitrary, capricious, not supported by substantial evidence and in violation of its due process rights.

D. Virginia

1. Overall NUG Project Totals in Virginia

As of the beginning of 1993, Virginia Power had approximately 3500 MWs of operating NUG capacity under contract from 55 facilities. An additional 950 MWs of capacity under contract to Virginia Power are under construction and/or development. Nearly all of this capacity resulted from Virginia Power's 1986, 1988, and 1989 Solicitations. To date, Virginia Power has also terminated approximately 1000 MWs of contracts from those solicitations, which is only slightly above the 20% attrition rate Virginia Power had projected from these solicitations. Operating history of these facilities has been quite good with availabilities generally equal to or better than Virginia Power's own system.

Lenders have foreclosed upon one facility under contract to Virginia Power and the Lenders are currently negotiating with Virginia Power to purchase that facility from the Lenders. That facility is the 80 MW SPP North Branch Project in Grant County, West Virginia near Virginia Power's Mt. Storm Power Station.

2. Virginia Power Solicitation

In 1990, Virginia Power announced the winners of its 1989 solicitation for non-utility generation projects. The winners were a 40 MW trash-to-energy project planned by Wheelabrator Technologies for Portsmouth, Virginia, a 200 MW coal gasification project planned by Virginia Iron in the Hampton - Newport, News, Virginia area and a 200 MW coal fired project planned by a subsidiary of the Southern Company for the King George County area near Fredericksburg. This was the last solicitation held by Virginia Power. In conjunction with the announcement of the winners, Virginia Power also announced plans to construct a 400 MW coal fired facility to come on-line in 1997. The 1997 unit has since been deferred due to lack of system growth then forecasted by Virginia Power.

Of the bid winners the Wheelabrator contract was transferred to Westmoreland Energy to become a second coal-fired facility adjacent to Westmoreland's facility under construction in Roanoke Valley, North Carolina. The Southern Company project is expected to close on its financing and begin construction in 1993, and the Virginia Iron project contract was canceled by Virginia Power.

3. Arbitrations

Shortly after Virginia Power issued the 1989 Solicitation, Smith Cogeneration of Virginia, Inc. (SCV) asked Virginia Power to negotiate a contract for a 320 MW coal-fired facility in the Danville area outside the bidding process. Virginia Power declined. SCV then petitioned the Virginia State Corporation Commission (VSCC) to arbitrate negotiations under the then existing VSCC

orders providing that the VSCC would arbitrate negotiations for facilities larger than 3 MWs. Virginia Power argued that bidding was the exclusive means of soliciting and contracting for NUG projects as authorized by the VSCC in an order dated January 29, 1988¹⁴⁴ authorizing competitive bidding. At about the same time as Virginia Power announced the winners of the 1989 solicitation and construction of the 1997 400 MW unit, the VSCC issued an order requiring Virginia Power to negotiate with SCV.¹⁴⁵ As of June, 1993 the SCV arbitration is still being mediated by a VSCC hearings examiner. In addition to the petition for arbitration filed by SCV an arbitration filed by Tellus, Inc.,¹⁴⁶ in 1987 is still active. A proposed Tellus contract negotiated by Tellus and Virginia Power was submitted to the VSCC for approval in 1990, but the VSCC declined to approve the agreement stating that it did not approve contracts with NUGS. Negotiations resumed. LG&E Power Systems made an agreement with Tellus to take over its PURPA rights for the project. By 1993, LG&E had pulled out and Virginia Power moved to dismiss the arbitration. Tellus has responded that it still is pursuing the project. Details of the SCV and Tellus arbitrations are under confidentiality orders from the hearings examiners conducting negotiations.

LG&E Power Systems was engaged in an arbitration proceeding against Old Dominion Electric Cooperative for a 160 MW coal-fired facility from 1990 through early 1993. Recently the parties settled their arbitration for a 51 MW sale from currently undesignated generating sources.

4. Competitive Bidding Rules

Simultaneous with the SCV order, the VSCC issued a rulemaking to establish rules for competitive bidding in Virginia.¹⁴⁷ That order provided that Virginia Power and other utilities would not be obligated to accept any offers from qualifying facilities pending the development of rules by the VSCC.

The most important points from the rules adopted by VSCC order dated November 28, 1990 include:

- (1) a utility with an "active" competitive bidding program is not obligated to accept offers, even from QFs outside of such bidding process;
- (2) the utility is not obligated to reveal to bidders the utility "benchmark" cost for its own construction plans;
- (3) a utility and a developer may jointly petition the VSCC for exceptions to the exclusivity of bidding when circumstances so warrant.

5. Virginia Power Credit Rating

In December, 1991, two rating agencies lowered Virginia Power's credit rating. Each attributed this "lowering" of Virginia Power's credit rating to Virginia Power's reliance on large amounts of capacity being purchased from

144. No. PUE870080.

145. See No. PUE890076 (April 25, 1990).

146. No. PUE870046.

147. See No. PUE900029.

non-utility generators rather than the utility constructing units itself. Upon close analysis, at least one of the credit rating agencies seemed to suggest that the "lowering" of the rating would have been greater or least equal had Virginia Power added the same amount of capacity through construction of its own units. This precise issue is currently being evaluated by the VSCC¹⁴⁸ in its section 712 investigation pursuant to the 1992 Act.

6. Coastal Power Project

An affiliate of Coastal Power Production Company made an offer to Virginia Power to construct a coal gasification project in southwestern Virginia as part of a U.S. Department of Energy Clean Coal grant program. Virginia Power held several meetings with Coastal Power in 1992. Virginia Power declined to award Coastal a contract for new capacity outside of its competitive bidding process. Virginia Power also stated that it did not anticipate needing a new solicitation for capacity prior to 1994 or 1995. Coastal Power offered to defer its facility to the year Virginia Power would need additional capacity. Coastal Power also offered to construct the unit at whatever it would cost Virginia Power to construct base load coal-fired capacity, i.e., at "avoided costs." Ultimately, Coastal Power attempted to have legislation passed in the Virginia General Assembly that would require Virginia Power to purchase the capacity at prices established as reasonable by the VSCC. The legislation was not passed by the General Assembly in the 1993 session.

7. Schedule 19

Virginia Power's standard rates for small QFs (i.e. 3 MWs or less) are contained in the Company's rate tariff known as "Schedule 19." In the fall of 1991, the biannual proceeding to revise those rates took place, with new rates effective January 1, 1992. Rates were significantly increased. By the summer of 1992, Virginia Power had received offers for nearly 200 MWs of Schedule 19 projects. As a result, Virginia Power ceased signing contract and unilaterally changed the terms of its standard Schedule 19 contract. Developers petitioned the VSCC alleging that the Virginia Power change in the terms of the contract amounted to a violation of the terms of the VSCC approved and mandated Schedule 19 tariff. In February 1993, the VSCC found Virginia Power's arguments persuasive and ordered the Virginia Power contract change to be part of the Schedule 19 tariff and that the tariff now only apply to the PURPA minimum level for standard rates of 100 kw. Several developers have appealed the VSCC decision to the Virginia Supreme Court.

8. IPP/EWGs

Two large non-QF or IPP facilities are now operating in Virginia, Doswell, L.P. (650 MWs) and Commonwealth Atlantic, L.P. (320 MWs), from the 1986 and 1988 Solicitations respectively. Doswell and CALP were each issued Certificates of Convenience and Necessity by the VSCC.¹⁴⁹ After

148. No. PUE930015.

149. See No. PUE890068.

approval of Doswell and CALP, the VSCC issued procedures and filing requirements for non-QF or IPP facilities.¹⁵⁰ One facility has filed under those rules.¹⁵¹

9. Disallowance of payments to Non Utility Generators

In Virginia Power's 1992 rate case,¹⁵² the VSCC staff alleged that payments to nearly two dozen NUGs wrongfully contained amounts to cover portions of "avoided costs" that Virginia Power will not actually "avoid." The alleged error is based upon gross receipts taxes applicable to the revenue collected by Virginia Power for sales to its customers. Most of the potentially effected contracts contain "regulatory out" clauses that will allow Virginia Power to eventually recover from NUGs any payments made to NUGs for which the VSCC denies recovery by Virginia Power from its ratepayers. A hearing is scheduled for September, 1993.

10. Dispersed Energy Facility Tariff

In June of 1993, Virginia Power applied for approval of an experimental tariff from the VSCC. Called the "Dispersed Energy Facility Tariff" it appears to provide for Virginia Power to construct and operate "inside-the-fence" electric and steam production facilities for individual large industrial customers. Virginia Power alleges that the industrial customer would pay all costs of constructing, maintaining, and operating such facilities and that such facilities will earn a rate of return that will be shared with other ratepayers. Virginia Power also alleges that this is necessary to prevent these industrial customers from dropping off the system to self-generate, which according to Virginia Power, would increase rates for the customers left behind on the systems. Several NUG developers are expected to intervene at the VSCC in the VSCC proceeding to evaluate approvals of this tariff.

11. Local Taxation of Capacity Payments

Several localities in Virginia are attempting to collect a business license tax on the capacity payments paid by Virginia Power to NUGs in such localities. In Virginia, "manufacturers" are generally exempt from business license taxes usually applied to "service" businesses. Cogenerators have been found to be "manufacturers" in Virginia. The localities contend that the capacity payment received by a dispatchable facility is not received by the NUG because of "manufacturing" and therefore does not qualify for the manufacturing exemption. A suit has been filed by several NUGs in Hopewell, Virginia to ask a court to resolve the issue.

150. See No. PUE900044.

151. Patowmack Power Partners made an application for a facility to be located in Virginia that would sell power to PEPCO in D.C. and Maryland. See No. PUE910081. The Virginia process was put on hold when project approvals required by the DC and Maryland PSC's stalled.

152. No. PUE920041 (1992).

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