

Report of the Committee on Non-Utility Generation

I. FEDERAL DEVELOPMENTS

A. FERC

1. QF Developments

(a) Utility Ownership:

(1) "Electric Utility" Defined

In *Long Lake Energy Corp.*,¹ the Federal Energy Regulatory Commission ("Commission or FERC") interpreted the definition of electric utility, as that term is applied in section 292.206 of the Commission's regulations.² At issue was the effect of ownership in Atlantic Limited Partnership ("Commonwealth"), the owner of an electric generating facility. Long Lake Energy Corporation ("Long Lake Energy"), which owned 50% of Commonwealth through its subsidiaries, requested the Commission to clarify that its ownership interest in Commonwealth would not affect the status of qualifying facilities ("QFs") that it owned.³ More specifically, Long Lake Energy requested that the FERC find that it was neither an electric utility nor an electric utility holding company.

The Commission began its analysis with section 3(22) of the Federal Power Act ("FPA"), which defines electric utility as ". . . any person or state agency which sells electric energy."⁴ Next, the FERC looked to section 3(4) of the FPA which defines person as "an individual or a corporation."⁵ Turning to section 3(3) of the FPA,⁶ which defines "corporation", the FERC held that the definition of corporation (including partnership) does not reach upstream subsidiaries or affiliates.⁷ The Commission concluded that Long Lake Energy would not be affected by Commonwealth becoming an electric utility because the definition of electric utility does not reach upstream to give the parent corporation the classification of its subsidiary.

(2) "Primarily Engaged In" Standard

In a case of first impression, the Commission denied the United States Army Corps of Engineers ("Corps") QF certification for a hydroelectric facility on the grounds that the Corps was primarily engaged in the generation and sale of electric power.⁸ In reviewing the statutory framework under which the

1. *Long Lake Energy Corp.*, 51 F.E.R.C. ¶ 61,262 (1990).

2. 18 C.F.R. § 292.202 (1991).

3. 51 F.E.R.C. ¶ 61,262, at 61,771.

4. 16 U.S.C. § 796(22) (1988).

5. 16 U.S.C. § 796(4) (1988).

6. 16 U.S.C. § 796(3) (1988).

7. 51 F.E.R.C. ¶ 61,262, at 61,772.

8. *United States Army Corps of Engineers*, 47 F.E.R.C. ¶ 61,003 (1989).

facility operated, the FERC observed that power marketing administrations ("PMAs") were statutorily responsible for marketing the Corps' electric power. The Commission determined that it "must view the Corps/PMA generating/marketing function as an integrated whole."⁹ Consequently, the FERC concluded that together, the Corps and the PMAs must be considered primarily engaged in the generation and sale of electric power.

The Commission subsequently distinguished its decision when it granted the application of the United States Army Training Center and Fort Dix ("Fort Dix") for certification as a qualifying cogeneration facility.¹⁰ Although Fort Dix engaged in limited sales of electric power, the FERC held that Fort Dix was not primarily engaged in the generation or sale of electric power. The reason for this result was that Fort Dix was not required to participate in a marketing relationship with PMAs.

(3) Capital Contributions

In *HL Power Co.*,¹¹ the Commission held that a partnership in which not more than 50% of the stream of benefits flowed to the electric utility partners satisfied its ownership criteria, notwithstanding the fact that the capital contributions of the partners were disproportionate to their respective partnership percentages. The FERC further held in *CMS Midland, Inc.*¹² that the reduction of a partner's deemed investment in a QF as the result of a partnership restructuring was irrelevant to certification as it was merely part of the "give-and-take" bargains struck between nonaffiliated parties.

(4) Control Issues

In *Ultrapower Inc.*,¹³ the Commission approved two identical joint venture agreements, both of which provided for a management committee comprised of four members. Under the agreements, utility partners were to appoint one member and non-utility partners were to appoint another member. The remaining two members were to be chosen by a partner owned equally by utility and non-utility interests. This partner was given the option of selecting its own independent members, or designating the utility and non-utility members as its representatives. The FERC concluded that the "practical effect" of the arrangement was to prevent either the utility or non-utility interests from gaining control by allocating each two votes.

In *Modesto Energy Ltd. Partnership*,¹⁴ the Commission distinguished the ownership analysis applicable to partnership structures from those applicable to corporate structures. The FERC explained that in order to apply the own-

9. *Id.* at 61,010.

10. United States Army Training Center and Fort Dix, 48 F.E.R.C. ¶ 61,041 (1989).

11. HL Power Co., 50 F.E.R.C. ¶ 61,208 (1990).

12. CMS Midland, Inc., 50 F.E.R.C. ¶ 61,098 (1990).

13. Ultrapower Inc., Rio Bravo Jasmin, 46 F.E.R.C. ¶ 61,380 (1989).

14. Modesto Energy Ltd. Partnership, 55 F.E.R.C. ¶ 61,355 (1991).

ership regulations to partnership structures, it must determine the partners' equity interests. These equity interests, in turn, are dependent upon the partners' share of the stream of benefits and control of the venture.

Corporate structures, however, are subject to a much simpler analysis. The Commission explained that where there is only one class of common stock, the sole issue is whether or not an electric utility interest owns more than 50% of the common stock. If the interest is less than 50%, then the facility is in compliance with the ownership regulations and the analysis ends. The FERC also noted that even if the electric utility interest gained majority control of the board of directors, the ownership regulations would not be violated provided that the electric utility interest never obtained more than 50% of the common stock.

The Commission subsequently applied this corporate ownership analysis in *Watsonville Cogeneration Partnership*.¹⁵ The facility in *Watsonville* was owned by a corporation with a single class of common stock. Although an electric utility interest held 46.5% of the owner's common stock, restrictions prevented it from acquiring more than 49% of the common stock. Applying the corporate ownership analysis from *Modesto*, the FERC concluded that the electric utility interest could obtain majority representation on the owner's board of directors without violating the ownership regulations.¹⁶

(5) Net Present Value

In *Sissonville Ltd. Partnership*,¹⁷ the Commission approved a limited partnership agreement which provided for a special allocation of tax benefits to the utility partner.¹⁸ Under the limited partnership agreement, the utility partner was to receive most of the investment tax credits and depreciation deductions attributable to the facility during the early years of operation.¹⁹ The applicant argued that any economic benefit derived by the utility partners from this special allocation was more than offset by the greater initial capital contributions of the utility partner and by the allocation of greater cash flow and income (in the later years) to the non-utility partner. In support of this argument, the applicant submitted a time value analysis which demonstrated that the net present value of all profits and losses would not result in the utility partner receiving more than 50% of the partnership's stream of benefits.

The FERC added an additional requirement to the net present value analysis in *Dravo Energy Resources of Montgomery County, Inc.*²⁰ That partnership agreement provided that the utility partner was to make capital con-

15. *Watsonville Cogeneration Partnership*, 57 F.E.R.C. ¶ 62,121 (1991).

16. *Id.* at 63,187.

17. *Sissonville Ltd. Partnership*, 53 F.E.R.C. ¶ 62,221 (1990).

18. The Commission approved identical limited partnership agreements in *Middle Falls Ltd. Partnership*, 53 F.E.R.C. ¶ 62,222 (1990); *NYSD Ltd. Partnership*, 53 F.E.R.C. ¶ 62,223 (1990).

19. 53 F.E.R.C. ¶ 62,221, at 63,341.

20. *Dravo Energy Resources of Montgomery County, Inc.*, 57 F.E.R.C. ¶ 62,017 (1991). *See also*

tributions in excess of 50% and receive benefits in excess of 50% during the early years of operation.²¹ According to a net present value analysis submitted by the applicant, the utility partner would receive no more than 50% of the stream of benefits because its disproportionate capital contributions would offset its disproportionate benefits. While the FERC did not reject the applicant's present value analysis, it questioned the accuracy of the underlying expense and revenue projections. To ensure that the utility partner would not receive more than 50% of the stream of benefits, the Commission required the utility partner to submit a report upon completion of its participation in the facility on the net present value of benefits actually received and to pay to the non-utility partners any amounts necessary to bring its share of the stream of benefits within the 50% limit.

(6) Sale-Leaseback Arrangements

The Commission denied QF certification of a hydroelectric project involving a sale-leaseback arrangement in *Allegheny Electric Cooperative, Inc.*²² Under the sale-leaseback arrangement, the owner, Allegheny Electric Cooperative ("Allegheny"), agreed to sell the facility to Connecticut Bank and Trust Company ("CBT"). CBT, as owner/trustee, held legal title to the facility for the benefit of Ford Motor Credit Company ("Ford"), the owner participant. Pursuant to a separate lease agreement, Allegheny leased the facility from CBT for an initial period of 30 years. The lease agreement provided that Allegheny was to retain control over the operation and provide for maintenance of the facility.

For purposes of determining whether the facility was owned by a person primarily engaged in the generation or sale of electric power, the Commission looked to Allegheny. As the Commission explained:

Although the Owner Participant and the Owner Trustee have legal or equitable title to the facility, they have no voice in or dominion over the maintenance and operation of the facility. Instead, Allegheny will continue to have complete control over its maintenance and operation. . . . Thus, the instant sale-leaseback transaction is merely a financing mechanism from which the Owner Participant derives certain tax and investment benefits while Allegheny benefits from lower financing costs.²³

The FERC found that Allegheny was an electric utility due to its control over the facility and denied certification.

(b) Sale of Gross Output by Qualifying Facilities

The Commission has historically measured the capacity of small power production facilities based on the net output, rather than the gross output of

Zond Victory Garden Phase IV Development Corp., 57 F.E.R.C. ¶ 62,018 (1991); Zond Sky River Development Corp., 57 F.E.R.C. ¶ 62,019 (1991).

21. 57 F.E.R.C. ¶ 62,017, at 63,023.

22. Allegheny Elec. Coop. Inc., 47 F.E.R.C. ¶ 61,015 (1989).

23. *Id.* at 61,054

the facility. In other words, power produced for the facility's own use for station services is not included in determining the facility's power producing capability. This has been an advantage in the case of small power production facilities because it has enabled larger facilities to satisfy the 30 and 80 MW size limits imposed on small power production facilities.²⁴

However, in *Penntech Papers Inc.*,²⁵ the Commission dropped the other shoe, and considered the impact of this rule on cogeneration projects. *Penntech Papers* involved a cogeneration project which produced power for sale outside of the service territory of the local utility and was directly interconnected with the purchasing utility. The developer wanted to sell the project's gross output to the purchasing utility and buy station service power from the local utility. The FERC certified the project as a QF with a capacity equal only to the project's net output.

In *Penntech Papers*, the Commission did not expressly discuss the consequences of selling the gross output of the project. However, that issue was addressed in the subsequent orders of *Turners Falls Ltd. Partnership*, Order Denying Request For Waiver and Granting Application for Recertification as a Qualifying Cogeneration Facility²⁶ and Order on Request for Clarification.²⁷ In the Order Denying Request for Waiver, the FERC again refused to certify the gross output of a cogeneration project. In the Order on Request for Clarification, the Commission spelled out the consequences of selling the gross output of the project. The FERC confirmed that because the incremental output in excess of the net output of the project was not considered to be power produced by a QF, the sale of the output caused the owner of the QF to fail the "primarily engaged" test. It follows that, because the owner of the facility is an electric utility, the entire facility loses its qualification as a QF and must operate, if at all, as an IPP. It also follows that the upstream owners of the facility would become utilities for purpose of the utility ownership test, and would have to bring non-utility partners into any of the upstream owners' other projects.

With the increasing frequency of wheeling transactions, it is not uncommon for a project to be interconnected directly with a utility outside the service territory in which the project is located. Under these circumstances, it will frequently be to the advantage of the facility and the local utility for the project to sell all of its gross output to the purchasing utility and purchase all of its station services from the local utility. Moreover, technical considerations, such as the wear and tear on generating equipment associated with frequent switching from station power to the local utility may also dictate that all station power be purchased from the local utility. Finally, the interconnected

24. See *Occidental Geothermal, Inc.*, 17 F.E.R.C. ¶ 61,231 (1981); *Massachusetts Refusetech, Inc.*, 25 F.E.R.C. ¶ 61,406 (1983); *Power Developers, Inc.*, 32 F.E.R.C. ¶ 61,101 (1985).

25. 48 F.E.R.C. ¶ 61,120 (1989).

26. *Turners Falls Ltd. Partnership*, 53 F.E.R.C. ¶ 61,075 (1990).

27. *Turners Falls Ltd. Partnership*, 55 F.E.R.C. ¶ 61,487 (1991).

utility may not be willing to sell backup and standby power to the QF or, if it is willing, the interconnected utility may find that such sales are prohibited by state law or the local utility's franchise. Unfortunately, despite the technical and legal justification for such gross output sales, it is now clear that these arrangements are not permitted under the Commission's regulations.

2. Developments Affecting IPPs

(a) Market-Based Rates

In 1991, the Commission continued to consider market-based rate proposals by non-utility generators, such as independent power producers ("IPP"), on a case-by-case basis. In these instances, the Commission evaluated whether the seller, or its affiliates, lacked market power to the extent that they were not a dominant generation firm and could not control relevant transmission facilities. In addition, the potential for abuse of affiliate relations also remained an issue. Through its orders, and a series of public comments and hearings, the Commission indicated that certain guidelines may be established that could prove useful to non-utility generators seeking to use market-based rates.

The Commission has accepted an independent power producers' initial rate schedule containing market-based rates without a substantive discussion of market power where a competitive bidding process and subsequent negotiations were involved, and no affiliation questions were presented.²⁸ However, the Commission has questioned situations where issues of market power (or affiliation) are present. In *Nevada Sun-Peak Ltd. Partnership*,²⁹ the FERC examined questions of market power in generation and the impact of a state agency's approval of the transaction that used market-based pricing. The purchasing utility decided that there was insufficient time to follow a formal solicitation process and, instead, approached two companies with which it had dealt on QF projects, ultimately accepting the one that could meet its schedule. The Public Service Commission of Nevada eventually approved a stipulation which contained market-based pricing provisions.

The seller, Nevada Sun-Peak Ltd. Partnership ("Sun-Peak"), submitted the power purchase contract to the Commission, and requested that the rates be found "just and reasonable" under section 205(a) of the Federal Power Act.³⁰ The FERC again stated its test to determine whether a lack of market power existed:

To demonstrate that proposed rates were not influenced by the seller's market power, the seller must establish that neither it nor any of its affiliates: (1) is a dominant firm in the sale of generation services in the relevant market; (2) owns or controls transmission facilities through which the buyer could reach other sellers or, if it or its affiliates do own such facilities, it has adequately mitigated

28. See *Walkill Generating Co., L.P.*, 56 F.E.R.C. ¶ 61,067 (1991) (waivers of regulations granted).

29. 54 F.E.R.C. ¶ 61,264 (1991); 55 F.E.R.C. ¶ 61,058 (1991).

30. 16 U.S.C. § 824d(a).

any ability to block the buyer from reaching other sellers; and (3) is able to erect or otherwise control any other barrier to entry.³¹

The Commission found that Sun-Peak failed to meet its burden in demonstrating that it was not a dominant supplier to the purchasing utility. More specifically, Sun-Peak presented no evidence to show that the purchaser considered any feasible alternative to Sun-Peak except self-construction. The Commission stressed that evidence of “actual alternatives” must be presented, instead of evidence addressing only “potential competition.”³² Moreover, the fact that it was the purchaser that initially limited its own market search did not relieve Sun-Peak of its burden. The Commission stated:

[A]ny supplier seeking market-based rates is affected by the actions of its buyer. When buyers conduct a well-organized and comprehensive market search, either by competitive bidding or negotiation, they can provide the supplier with much of the needed evidence. When buyers limit their options, the supplier’s evidentiary task is more difficult. Whatever the cause, however, Sun-Peak has not, based upon the current record, met its evidentiary burden as to generation dominance and cannot receive market-based rates.³³

The Nevada Public Service Commission’s approval of the transaction also failed to support Sun-Peak’s proposal before the Commission. The state agency’s review was found to be limited to the purchaser’s need for capacity and a cost comparison to the single alternative of self-construction. The Commission held that this was an insufficient basis on which to determine whether rates are “just and reasonable” under the Federal Power Act. On rehearing, the Commission determined that Sun-Peak’s rates were justified on a cost basis, and therefore did not address arguments raised on rehearing by Sun-Peak and the Nevada Commission, which had attempted to justify the market-based rates.

The Commission addressed market-based pricing, particularly in the context of transmission access, when it considered requests by members of the Western Systems Power Pool (“WSPP”) for permanent approval of an experiment concerning flexible pricing for coordination and transmission services.³⁴ IPPs and power marketers were allowed to join the WSPP, but the Commission rejected continued use of market-based rates because of insufficient proof that the participants lacked or adequately mitigated generation and transmission market power. The practice of charging captive utilities more than was charged other utilities for power and short term transmission services was found to be an exercise of market power. Market power also resulted from the ability of owners of transmission services to charge more for short-term transmission services when transmission capacity was scarce. In addition, cost-based rates were favored, in the circumstances of this case, because they could discipline rates for short-term transmission service.³⁵

The Commission also found that the WSPP’s transmission proposal

31. 54 F.E.R.C. ¶ 61,264, at 61,769.

32. *Id.*

33. *Id.*

34. Western Sys. Power Pool, 55 F.E.R.C. ¶ 61,099 (1991); 55 F.E.R.C. ¶ 61,495 (1991).

35. 55 F.E.R.C. ¶ 61,099, at 61,316-17.

neither required the provision of any transmission service nor guaranteed transmission to purchasers for service from other suppliers, and therefore did not adequately mitigate market power. The Commission rejected claims that its intention was to implement "perfect competition," and found that its standard permitted certain "market imperfections," provided that the seller seeking approval of market-based prices cannot "influence significantly the price to the buyer."³⁶

The Commission considered a proposed sale of capacity and energy between affiliates, at market-based rates, in *Boston Edison Co. Re: Edgar Electric Energy Co.*³⁷ There, Edgar Electric Energy Company, a subsidiary of Boston Edison Company, contracted to sell capacity and energy from a 306 MW combined-cycle generating unit that was not yet built. The Commission stated that in order to permit non-traditional pricing, there must be a showing that there is no potential abuse of self-dealing or reciprocal dealing. In this regard, it was "essential that ratepayers be protected and that transactions be above suspicion in order to ensure that the market is not distorted."³⁸ Where the "mere opportunity" of affiliate abuse exists, the Commission will analyze the facts since the "rate may not be just and reasonable because the buyer potentially may have unduly favored the rates offered by its affiliate seller over lower rates offered by other non-affiliated sellers."³⁹ Thus, the Commission stated that the first step in its analysis is to ensure a lack of self-dealing. In so doing, factors that may apply in a market-power determination (such as the number of supply options or the seller's ability to control transmission) will not apply where a transaction between affiliates is proposed. As a result of the potential for self-dealing:

[T]he Commission must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and nonprice terms (i.e., that it has not preferred its affiliate without justification).⁴⁰

The Commission discussed three possible methods to eliminate concerns of preferential pricing. The first method was the "market value" test, which applies a bid or benchmark standard to determine market value. The second method was evidence of prices which non-affiliated buyers are willing to pay for similar service from that particular generation project (but only if the non-affiliated buyers are in the same market as the purchaser, and are not subject to the exercise of market power by the seller or affiliates). The third was benchmark evidence which shows the prices, terms and conditions of sales made by nonaffiliated sellers. With respect to the third line of evidence, the Commission also stated that it would consider whether the benchmark sales are contemporaneous and for services that are similar to the proposed transaction.⁴¹

Applying these considerations, the Commission found that certain bench-

36. 55 F.E.R.C. ¶ 61,495, at 62,714-15.

37. *Boston Edison Co. Re: Edgar Elec. Energy Co.*, 55 F.E.R.C. ¶ 61,382 (1991).

38. *Id.* at 62,167 (footnote omitted).

39. *Id.* at 62,167-68 (footnote omitted).

40. *Id.* at 62,168 (footnote omitted).

41. *Id.* at 62,168-69.

mark data submitted by Boston Edison failed to show that the contract rates were just and reasonable. Boston Edison sought to compare the price and non-price terms of its Edgar contract with other supply contracts in the region. However, differing assumptions underlying the various contracts were not explained by Boston Edison.

In other proceedings the Commission re-examined previously approved market-based rates to ensure that no self-dealing or reciprocal dealing would result from a proposed disposition or transfer of an interest in the seller.⁴² These analyses included an evaluation of whether the new party acquired its interest for anything other than a fair market value which would raise "the possibility of future reciprocal dealing."⁴³

In Docket No. PL91-1-000, the Commission issued a notice of its intention to hold a public conference on certain key issues in the electric utility industry.⁴⁴ Recognizing that it has addressed requests for market-based rates from entities which include independent power producers and affiliated power producers, the following questions were among those raised in the notice: (1) Should the Commission act on a case-by-case basis, or under generic guidelines, in evaluating market-based rate proposals? (2) Have the Commission's past analyses of such proposals been consistent and comprehensive? (3) How can the Commission provide greater regulatory certainty to those parties that seek to use market-based rates in their transactions? (4) Has the Commission adequately protected against affiliate abuse problems associated with affiliated power producers/marketers? As a part of this proceeding, Commissioner Trabandt suggested the adoption of some form of "safe harbor" guidelines that would permit certain market-based rate transactions to be subject to an abbreviated procedure resulting in automatic approval.⁴⁵ Under these general guidelines, it was proposed that a non-protested transaction could be approved where the seller is an independent entity not affiliated with the purchaser or any utility interconnected with the purchaser, the seller does not own or control transmission that reaches the buyer (or any other item that the buyer must depend on), and the seller offers new capacity.

In another development, the Commission had the opportunity to announce its policy concerning the timing of electric rate filings. The Commission stated that its regulations require that rates be filed 60 days before the expected date service will commence and that would be waived only "in extreme circumstances" if rates are market-based.⁴⁶

3. Transmission Access

(a) "Mandatory" Transmission Access

There were two principal developments with respect to the Commission's

42. Commonwealth Atlantic Ltd. Partnership, 57 F.E.R.C. ¶ 61,193 (1991); Doswell Ltd. Partnership, 57 F.E.R.C. ¶ 61,079 (1991).

43. See, e.g., 57 F.E.R.C. ¶ 61,079, at 61,292 (1992) (footnote omitted).

44. 55 F.E.R.C. ¶ 61,069 (1991).

45. 55 F.E.R.C. ¶ 61,069 (1991) (questions from Comm'r Trabandt).

46. Central Me. Power Co., 56 F.E.R.C. ¶ 61,200, at 61,818 (1991); 57 F.E.R.C. ¶ 61,083 (1991).

authority under section 203 of the FPA to "mandate" open access in approving mergers of public utilities. The issue in both instances was the Commission's decision to exclude non-utility users from the conditions imposed on the merged utility to provide transmission access.

On August 9, 1991, the Commission conditionally authorized the Public Service Company of New Hampshire to dispose of all of its jurisdictional facilities and merge with Northeast Utilities Service Company.⁴⁷ The Commission conditioned its approval of the Northeast Utilities merger on the requirement that the merged utility provide firm and non-firm transmission access to "any utility," although the merged utility retained priority for delivery of the output of its own generating units to its native load, its existing contractual requirements, and firm versus non-firm service.⁴⁸ As part of its merger transmission commitments, Northeast Utilities also incorporated a settlement with New England Power Company known as the New Hampshire Corridor Plan ("Corridor Plan"). Under the Corridor Plan, eligibility would not be offered to QFs unless they agreed to waive their Public Utility Regulatory Policies Act of 1978 ("PURPA")⁴⁹ rights to require a utility to purchase from them at full avoided cost rates.⁵⁰

On January 29, 1992, the Commission issued its Order on Rehearing in the Northeast Utilities merger.⁵¹ This order followed the Commission's Order on Remand in the Utah Power & Light/PacifiCorp merger.⁵² Based on its reasoning in the Utah Remand, the Commission concluded that it had no authority to require Northeast Utilities to wheel power for QFs under the Corridor Plan.⁵³ The Commission, however, noted that QF owners may voluntarily elect to be treated as electric utilities as defined in section 3(22) of the Federal Power Act ("FPA")⁵⁴ and may then request wheeling under section 211.⁵⁵ Upon the request of Northeast Utilities and other interested parties, on October 1, 1991, the Commission issued an order granting rehearing for the purpose of further consideration.

On August 2, 1991, in *Environmental Action, Inc. v. FERC*,⁵⁶ the United States Court of Appeals for the D.C. Circuit, remanded to the FERC its decision⁵⁷ approving the merger of Utah Power and Light and PacifiCorp. The

47. Northeast Util. Serv. Co., (Re Public Serv. Co. of N.H.) 56 F.E.R.C. ¶ 61,269 (1991), Order on Rehearing, 58 F.E.R.C. ¶ 61,070 (1992). The presiding judge's initial decision appears at 53 F.E.R.C. ¶ 63,020 (1990).

48. 56 F.E.R.C. ¶ 61,269, at 62,014-021.

49. 15 U.S.C. 79-79z-6 (1988).

50. 56 F.E.R.C. ¶ 61,269, at 62,041.

51. 58 F.E.R.C. ¶ 61,070.

52. Utah Power & Light Co., 57 F.E.R.C. ¶ 61,363 (1991) ("Utah Remand").

53. 58 F.E.R.C. ¶ 61,070, at 61,217.

54. 16 U.S.C. § 796(22) (1988).

55. 58 F.E.R.C. ¶ 61,070, at 61,218-219.

56. 939 F.2d 1057 (1991).

57. Utah Power and Light Co., 45 F.E.R.C. 61,095 (1988), Order on Rehearing, 47 F.E.R.C. ¶ 61,209 (1989).

court directed the FERC to reconsider its decision to exclude QFs and end-users from the transmission access conditions.⁵⁸

The court rejected the FERC's determination that mandatory transmission access gives QFs an unwarranted competitive preference.⁵⁹ The court noted that the avoided cost price should not distort the market since an inefficient QF could not effectively compete with lower-cost, non-QF suppliers.⁶⁰ In any event, the court concluded any arguable "advantage" for QFs stems directly from Congress' decision to ensure that large power producers do not discriminate against QFs, a decision which the Commission is not authorized to repeal.⁶¹

The court also rejected the Commission's conclusion that QFs will not suffer competitive harm by denial of access and stated that the FERC's decision left the merged utility free to broker QF power for profits on sales to distant markets, while the QF, held captive, must accept PacifiCorp's avoided cost.⁶² The court looked to consumer welfare concerns: the ability of the merged utility "to prevent lower priced competitors from reaching the market confers the power to charge consumers monopoly forces."⁶³ Finally, the court concluded that the Commission had failed to offer persuasive factual differences between QFs and other competitors (other than QF PURPA rights) to justify its discriminatory treatment of QFs.⁶⁴

On December 23, 1991, the Commission issued its order on remand,⁶⁵ which reaffirmed the Commission's decision to exclude QFs from the mandatory wheeling conditions. The Commission reasoned that Congress, in enacting PURPA, did not intend that QFs be given the same rights as utilities and IPPs to obtain mandatory wheeling.⁶⁶ Specifically, the Commission noted that Congress, in adding section 211 to the FPA in PURPA, did not list QFs among the entities that can request a wheeling order. This omission indicated to the Commission that Congress, in enacting section 211, did not intend QFs to have mandatory transmission access rights.⁶⁷ A QF owner, therefore, may only obtain mandatory transmission if it waives its PURPA rights and elects to be an "electric utility." Notably, Commissioner Moler, in a strongly worded dissent, concluded that none of the majority's reasons for denying QF access "withstands even minimal scrutiny" in light of the D.C. Circuit's *Environmental Action* opinion.⁶⁸ On April 9, 1992, the Commission issued its

58. 939 F.2d 1057, 1062 (D.C. Cir. 1991).

59. *Id.* at 1061.

60. *Id.* at 1061-62.

61. *Id.* at 1062.

62. *Id.*

63. *Id.*

64. *Id.*

65. *Utah Power & Light Co.*, 57 F.E.R.C. ¶ 61,363 (1991).

66. *Id.* at 62,187-188.

67. *Id.* at 62,188-189.

68. *Id.* at 62,197.

Order Denying Rehearing reiterating its conclusion that Congress' intent to exclude QFs from the Commission's wheeling authority under section 211 limits the Commission's authority to require wheeling for QFs under any circumstances, including imposing conditions in the public interest under section 203.⁶⁹

On March 11, 1992, several parties to the Court of Appeals litigation filed a petition for a Writ of Mandamus seeking the court's enforcement of its order in *Environmental Action*. The Commission responded on April 16th by arguing that its orders on remand fulfilled the Court's mandate. *Environmental Action* also filed a petition for review of the Commission's orders on remand.

(b) "Voluntary" Transmission Access

Several "voluntary" open access tariffs have been filed with the Commission. Entergy Services acting as an agent for Entergy Corporation submitted a tariff for approval on behalf of Arkansas Power and Light, Louisiana Power and Light, Mississippi Power and Light and New Orleans Public Service Company (collectively, "Entergy Companies") and Entergy Power, Inc. The tariff offered transportation service on transmission facilities of the Entergy Companies to "other electric utilities."⁷⁰ QFs would be granted access if they waived their rights under PURPA to make sales at full avoided cost rates.

On March 3, 1992, the Commission conditionally approved Entergy Services' tariffs and did not amend the provision whereby the QFs may obtain transmission service only if they waive their PURPA rights to make sales at full avoided cost rates.⁷¹ The Commission stated that this provision was consistent with its decision in the Utah Remand.⁷² The Commission reiterated its reasoning: (1) it has no statutory authority under PURPA to force utilities to wheel for QFs, and Congress excluded QFs from the entities that may seek wheeling under section 211 of the FPA; (2) QF access is not needed to prevent undue discrimination; (3) mandatory QF access is not necessary for the protection of the public interest; and (4) if a QF seeks electric utility status it would then be eligible for access under Entergy's tariff.⁷³ Not surprisingly, Commissioner Moler dissented from the Commission's decision on this point, stating that to deny QFs access unless they become electric utilities is contrary to Congress' statutory scheme in PURPA and the D.C. Circuit's opinion in *Environmental Action*.⁷⁴

Consumers Power Company ("Consumers") also filed a proposed "open access" interconnection services tariff.⁷⁵ Under the proposal, "eligible utili-

69. Utah Power & Light Co., 59 F.E.R.C. ¶ 61,035, at 61,113-119 (1992).

70. Entergy Services, Inc., 58 F.E.R.C. ¶ 61,234 (1992).

71. *Id.* at 61,761.

72. *See supra* note 52.

73. 58 F.E.R.C. at 61,761-763.

74. *Id.* at 61,775.

75. Consumers Power Co., 58 F.E.R.C. ¶ 61,232 (1992).

ties” may request Consumers to transmit coordination type power to utilities with which Consumers has an Interconnection or Operating Agreement. Consumers excluded QFs from the proposal on the grounds that no Commission filing is required for QFs to sell power to Consumers under the Commission regulations.

On March 23, 1992, the Commission conditionally approved Consumers’ tariff.⁷⁶ The Commission noted that certain QFs were not exempt from the Commission’s regulations and stated that although the Commission did not have the authority to force utilities to provide access to QFs, excluding certain QFs and not others would be unduly discriminatory.⁷⁷ The Commission, therefore, ordered Consumers to make the same terms and conditions available to all QFs or to exclude all QFs.⁷⁸

On February 27, 1992, Consumers filed an open access transmission proposal voluntarily including QFs as eligible utilities.⁷⁹ On April 30, 1992, the Commission accepted the tariff for filing and ordered a hearing on its justness and reasonableness. In its order, the Commission did not discuss Consumers’ inclusion of QFs and eligible utilities.

4. SEC: IPP Ownership Structures

On three separate occasions in 1991, the Securities and Exchange Commission (“SEC”) agreed that the acquisition and ownership of a limited partnership interest in an IPP would not subject the limited partner to regulation under the Public Utility Holding Company Act of 1935 (“PUHCA”).⁸⁰ Although most of the “law” in this area continues to evolve from informal “no-action” letters obtained from the staff of the SEC’s Division of Investment Management, which is responsible for the day-to-day administration of PUHCA, two related exemption applications, which have not yet been acted on, should help to clarify just how far investors in IPPs may go in using non-voting securities, such as limited partnership interests, to finance most of the equity requirements of an IPP.

As of July, 1992, both the Senate and the House of Representatives have passed their respective versions of the National Energy Strategy, which proposes to amend PUHCA and exempt most IPPs and their owners from PUHCA requirements. Compromise legislation should be agreed upon during a conference committee later this summer with the final version of the National Energy Strategy being sent to the White House for the President’s signature in the fall. The President has indicated he would veto any energy legislation which has an environmental package similar in scope to the present House bill, H.R. 776. Both H.R. 776 and the Senate bill, S.2166, passed their

76. *Id.*

77. *Id.* at 62,044-45.

78. *Id.* at 62,045.

79. Consumers Power Co., 59 F.E.R.C. ¶ 61,106 (1992).

80. 15 U.S.C. § 79a-79z-6 (1988).

respective chambers by wide margins. If the President does veto the compromise legislation, his veto might not be sustained by Congress.

(a) IPPs Under PUHCA

Unlike a QF, which is exempt from PUHCA by virtue of the Public Utility Regulatory Policies Act of 1978,⁸¹ an IPP is an "electric utility company" within the meaning of section 2(a)(3) of PUHCA⁸²; and any company (including a corporate general partner) which owns 10% or more of the voting securities of an IPP is a "holding company," as defined in section 2(a)(7)(A) of PUHCA.⁸³ In addition, any person (including any individual as well as any company) who acquires 5% or more of the voting securities of an IPP becomes an "affiliate," as defined in section 2(a)(11)(A) of PUHCA,⁸⁴ of the IPP, and the SEC's approval may be required for the acquisition itself under section 10 of PUHCA.⁸⁵ If required to register under PUHCA, a "holding company" and every subsidiary company thereof is subject to rigid SEC oversight with respect to such matters as capital structure and financing, affiliate transactions, management interlocks, and geographic integration of operations.

Under current law, the owners of the IPP (i.e., the stockholders or partners) must devise an ownership structure that will enable them to avoid regulation under PUHCA. Many companies that have traditionally supplied the equity capital needs of power project financing — including banks, insurance companies, equipment vendors and credit company affiliates of other large non-utility companies — will have difficulty qualifying for any of the narrowly drafted exemptions under section 3(a) of PUHCA⁸⁶ should they become "holding companies." Similarly, a holding company that already has an exemption may jeopardize that exemption by becoming a "holding company" with respect to an IPP located outside of its own service territory. As a result, IPP developers, in structuring the ownership of an IPP, have resorted to creative ownership structures in which voting control of the IPP is placed in the hands of an individual or a company that can qualify for an exemption under PUHCA, while other investors, who may in fact provide most of the equity requirements of the IPP, acquire non-voting securities, such as limited partnership interests or non-voting common stock.

For tax, legal and business reasons, most IPPs have been organized as limited partnerships. In many cases, the developer and general partner of an IPP will bring new equity investors into the project immediately prior to the commercial operation date of the facility — that is, the date on which, for

81. 16 U.S.C. § 824a (1988).

82. 15 U.S.C. § 79b(a)(3) (1988).

83. 15 U.S.C. § 79b(a)(7)(A) (1988).

84. 15 U.S.C. § 79b(a)(11)(A) (1988).

85. 15 U.S.C. § 79j(a)(2)(b) (1988).

86. 15 U.S.C. § 79(c) (1988).

purposes of PUHCA, the IPP becomes an "electric utility company." If the developer is unwilling to expose itself, as general partner, to potential regulation as a "holding company" after the facility goes into commercial operation then it may convert its interest in the partnership to that of a limited partner and bring a new unaffiliated general partner into the partnership. This is sometimes referred to as the "partnership flip." The new general partner may be an individual who, as such, does not fall within the definition of a "holding company," or a company which can qualify for an exemption under section 3(a) of PUHCA.⁸⁷

Whether the new investor comes in as a limited partner or as the new general partner, however, the limited partners in the IPP will usually want to obtain the SEC staff's assurances that they will not be regulated as a "holding company" or an "affiliate." Likewise, the general partner, if an individual, will want assurances that he or she will not be regulated as a "holding company" or, if a company, that the staff will not contest its exemption filing under section 3(a) of PUHCA.⁸⁸ As indicated, these issues are generally addressed in a "no-action" letter request rather than in any formal proceeding before the SEC. The parties to an IPP project financing, including the banks which supply most of funds needed to construct the facility, have generally been comfortable with the resolution of these issues at the staff level.

The three reported no-action letters in 1991 were *Nevada Sun-Peak Limited Partnership*⁸⁹ (SEC No-Action Letter, dated May 14, 1991); *Commonwealth Atlantic Limited Partnership*⁹⁰ (SEC No-Action Letter, dated October 30, 1991); and *ESI Energy, Inc.*⁹¹ (SEC No-Action Letter, dated December 2, 1991). The *Nevada Sun-Peak* and *Commonwealth Atlantic* structures utilize the so-called "partnership flip," in which the developer/general partner, a subsidiary of an exempt holding company, proposed to transfer a part of its interest to a new general partner and convert its remaining interest to that of a limited partner. In the Doswell Energy letter, the new investor proposed to become a limited partner in a limited partnership which will, in turn, be a limited partner in the IPP. The status of the project limited partner and of the ultimate parent of the project general partner is the subject of two related applications filed in July, 1991 requesting formal exemption orders under PUHCA. As indicated, those applications are pending.

(b) *Nevada Sun-Peak and Commonwealth Atlantic*

Nevada Sun-Peak,⁹² involved a 210 MW peaking facility developed by Mission Energy Company in Nevada to sell power to Nevada Power Com-

87. 15 U.S.C. § 79c(a) (1988).

88. *Id.*

89. 1991 SEC No Act. Lexis 719.

90. 1991 SEC No Act. Lexis 1280.

91. 1991 SEC No Act. Lexis 1422. [hereinafter Doswell Energy letter]

92. 55 F.E.R.C. ¶ 61,058 (1991).

pany. Mission was the sole general and limited partner of the partnership throughout the development and construction phase of the project, through two separate wholly-owned subsidiaries. However, just prior to the commercial operation date, Mission reduced its limited partnership interest to 50% and sold its general partnership interest, representing the remaining 50% of the interests in the partnership, to a new Nevada corporation which was thereupon admitted to the partnership as the sole general partner. The new general partner, a wholly-owned subsidiary of an individual who was in no way previously affiliated with the developer or the IPP, stated that it intended to seek an exemption under section 3(a)(1) of PUHCA,⁹³ which exempts so-called "intrastate" or "one-state" holding company systems.

Counsel for the developer argued that, as a limited partner, the developer would not acquire or own a "voting security," and thus would not become an "affiliate" or "holding company" with respect to the IPP. Under section 2(a)(17) of PUHCA,⁹⁴ a "voting security" is a security "presently entitling the owner or holder thereof to vote in the direction or management of the affairs of a company. . . ." Under the Sun-Peak partnership agreement, approval of a "majority in interest" of the limited partners is required for certain major partnership actions, including the sale of a material part of the assets of the partnership, incurring partnership debt, admitting new partners, dissolving the partnership, filing for bankruptcy in the name of the partnership, and amending any material term of the partnership agreement, among other things. Thus, the Mission Energy affiliate would clearly have the ability to block certain specified partnership actions that could directly affect its investment. In all other respects, management of the day-to-day affairs of the partnership would remain under the exclusive direction of the general partner. A "majority in interest" of the limited partners would also have the power to remove the general partner, but only "for cause," which would include a breach in fiduciary duty by the general partner, the general partner's bankruptcy, or a change in control of the general partner, among other things.

Citing a number of previous no-action letters on the subject, counsel argued, and the staff agreed, that the limited partner's approval rights with respect to certain major partnership actions and its ability to replace the general partner "for cause" would not enable the limited partner to vote in the "direction or management" of the partnership. Hence, the limited partnership interest would not be a "voting security," and Mission Energy Company would not be a "holding company" or "affiliate" with respect to the Sun-Peak partnership.

In addition, counsel asked the staff to confirm that it would not recommend any action to the SEC under section 2(a)(7)(B) of PUHCA⁹⁵ to deter-

93. 15 U.S.C. § 79c(a)(1) (1988).

94. 15 U.S.C. § 79(a)(17) (1988).

95. 15 U.S.C. § 79(a)(7)(B) (1988).

mine the limited partner to be a "holding company." Under section 2(a)(7)(B), the SEC may, after notice and opportunity for hearing, determine that a person is a "holding company," whether that person owns voting securities or not, if it finds that such person (either alone or in concert with others) exercises "such a controlling influence over the management or policies of any public utility or holding company as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that such person be subject to the obligations, duties and liabilities. . ." imposed under PUHCA on a holding company.⁹⁶ Counsel argued and again the staff agreed, that, based upon all the facts and circumstances of the case no such action under section 2(a)(7)(B) was warranted.⁹⁷ As evidence of the lack of any "controlling influence" by the limited partner, it was asserted that management of the Sun-Peak partnership would be under the exclusive control of the new general partner, who was in no way affiliated with the limited partner, and that the new general partner, who would acquire 50% of the equity interests in the partnership, had substantial experience in the industry managing similar kinds of power projects. Other factors, including the absence of any public investors and the adequacy of regulation of Sun-Peak by the FERC, were also cited as reasons why action by the SEC under section 2(a)(7)(B) was unnecessary to protect the public interest.⁹⁸

The *Nevada Sun-Peak* no-action letter was generally interpreted as affirming the SEC staff's view that, in order for an IPP developer to avoid regulation under PUHCA by converting its general partnership interest to a limited partnership interest just prior to commercial operation of an IPP facility, the new general partner would have to be unaffiliated with the developer and would have to acquire 50% or more of the interests of all partners in the partnership. Prior to the *Nevada Sun-Peak* letter, many felt that the staff would continue to follow its own advice in an earlier case, *Colstrip Energy Limited Partnership* (SEC No-Action Letter, dated June 30, 1988), in which the general partner would initially own only 4% of the equity interests of the partnership.⁹⁹ However, in March, a senior SEC staff member announced that the *Colstrip* no-action letter was not a precedent that the staff intended to follow in other cases then under consideration because, in his view, the *Colstrip* case was distinguishable. In *Colstrip*, the four individuals who had developed the project remained, indirectly through a company owned by them, the sole general partner of the partnership after the commercial operation date of the facility and the limited partners, who would acquire 96% of the partnership interests, had no previous equity interest or management role in the partnership. In other words, unlike the "partnership flip" structure, *Colstrip* was a case in which the persons controlling the partnership brought in the passive

96. 15 U.S.C. § 79(a)(7)(B) (1988).

97. *Id.*

98. *Id.*

99. 1988 SEC No Act. Lexis 805.

investor. The staff member stated that, for no-action letter ruling purposes, it would prefer to see a substitute general partner acquire at least 50% of the total equity of the partnership, presumably because it would be a more reliable indication of the new general partner's financial stake in the venture, thus assuring managerial independence.

The facts in the *Commonwealth Atlantic Ltd. Partnership* no-action letter were substantially identical to those in the *Nevada Sun-Peak* case. In fact, one of the two developers of the project who would become a limited partner on or prior to the project's commercial operating date was also a subsidiary of Mission Energy Company, and it is clear that the *Commonwealth Atlantic* structure was intended to mimic the *Nevada Sun-Peak* structure. In that respect, it was perceived as further affirmation of the SEC's position that, for no-action letter ruling purposes, the staff expected the new general partner to acquire at least 50% of the partnership interests. However, at about the time that the *Commonwealth Atlantic* letter was issued, the Director of the SEC's Division of Investment Management made a speech in which she stated that the staff would not, for no-action ruling purposes, focus on the percentage of the equity interests acquired by the new general partner. Rather, she stated, the staff would focus on the rights of the limited partners under the partnership agreement and other evidence of past or continuing relationships between the limited partners and the new general partner which would be evidence of a possible controlling influence by the limited partners. Presumably, then, the SEC staff is now prepared to consider a "partnership flip" structure more closely resembling the *Colstrip* model, although it has not done so to date.

(c) Doswell Energy Limited Partnership

In *Doswell Energy*,¹⁰⁰ the developer of the project, a 663 MW facility in Virginia that will sell power to Virginia Electric and Power Company has created a flexible ownership structure that will enable the developer to transfer voting control of the IPP to an outside investor if the preferred ownership structure is not approved by the SEC.

Under the preferred ownership structure, an affiliate of the developer ("Doswell I") will be the sole general partner and substantially all of the equity requirements of the project will be supplied by limited partnership investors. The developer is Diamond Energy, Incorporated ("Diamond"), a wholly owned subsidiary of Mitsubishi Corporation ("Mitsubishi"), a Japanese corporation. The general partner, Doswell I, is also an indirect wholly-owned subsidiary of Mitsubishi. The letter, dated December 2, 1991, is concerned only with the status of ESI Energy, Inc. ("ESI"), a subsidiary of FPL Group, Inc., an exempt holding company. ESI proposes to provide \$25,500,000 of the \$30,000,000 of equity required for the project, thereby reducing the developer's commitment. In the structure proposed, ESI will

100. See *supra* note 91.

invest as a limited partner in a limited partnership ("Doswell II LP") which, in turn, will be a limited partner in the project partnership ("Doswell LP"). An affiliate of Diamond is the managing partner in the second-tier limited partnership. An individual, not yet identified, would also invest \$1,500,000, and would become either a limited or general partner of Doswell LP, depending on the outcome of two related applications that Mitsubishi and Doswell II LP have filed.

As was the case in *Nevada Sun-Peak*,¹⁰¹ *Commonwealth Atlantic*,¹⁰² and other earlier no-action letter requests, the SEC staff was asked to concur that ESI would not become an "affiliate" or "holding company" with respect to Doswell LP as a result of acquiring, indirectly, a limited partnership interest. Although ESI will provide most of the funds to be invested by Doswell II LP in the project, it was stated that ESI would have very limited voting rights, generally restricted to partnership actions that could have a material impact upon its investment and will have no other role in the day-to-day management of Doswell II LP.

The *Doswell Energy*¹⁰³ no-action letter does not address the status of Mitsubishi (which, as the owner of Doswell I, the general partner, is itself a statutory "holding company,") or of Doswell II LP, the limited partner. In July, Mitsubishi filed an application for an exemption under section 3(a)(5) of PUHCA, which provides an exemption for any holding company which is not a utility in the United States and does not derive any "material part" of its income from any one or more subsidiaries which are utilities within the United States.¹⁰⁴ In effect, Mitsubishi asserts that it will not derive a material part of its income from Doswell LP. At the same time, Doswell II LP, as a limited partner, filed an application under section 2(a)(7) of PUHCA¹⁰⁵ not to be declared a "holding company." That section gives the SEC flexibility to declare a company which would otherwise fall within the presumptive part of the definition of a "holding company" not to be a holding company if it finds that such company does not directly or indirectly control a utility and does not "exercise . . . such a controlling influence over the management or policies of any public utility. . . as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the applicant be subject to the obligations, duties, and liabilities imposed . . . upon holding companies."¹⁰⁶ Presumably, the SEC staff declined to pass on Doswell II LP's status through the informal no-action letter request process because of the obvious influence which Mitsubishi will have over both Doswell I, the general partner, and Doswell II LP. These applications are pending.

101. See *supra* note 89.

102. See *supra* note 90.

103. See *supra* note 91.

104. 15 U.S.C. § 79c(a)(5) (1988).

105. 15 U.S.C. § 79b(a)(7) (1988).

106. *Id.*

As set out in ESI's no-action letter request, Mitsubishi and Diamond have a fall-back plan in the event that the Mitsubishi and Doswell II LP applications are denied. In such a case, the individual investor (or an entity controlled by one or more individuals who are not affiliates of Mitsubishi or Doswell I) would become the managing general partner of Doswell LP in place of Doswell I. This structure, should it come to pass, would resemble the "partnership flip" structure utilized in *Sun-Peak* and *Commonwealth*. The principal distinction being that the individual general partner would hold a 2 to 5% partnership interest rather than the 50% interest that the SEC staff had previously indicated that it would prefer to see in these structures.

(d) Mission Energy et al.

On June 29, 1992 the SEC issued an order approving an application by Mission Energy and its parent utility, SCEcorp. Mission Energy and SCEcorp had argued that the SEC could interpret PUHCA in a way that would permit United States utilities to invest in foreign IPPs.¹⁰⁷ The decision clears the way for SCEcorp and Mission Energy to purchase a 40 percent equity interest in Loy Yang B, a 1,000 MW coal-fired power station under construction in the State of Victoria, Australia. The order granting the 3(b) exemption was based on findings in three areas: (1) the size of the investment and the revenue it is expected to produce in comparison to the size and revenue of the exempt holding company; (2) a corporate structure that will protect U.S. ratepayers of Southern California Edison Company, SCEcorp's utility interest, from risks; and (3) confidence that state regulators will exercise adequate oversight. The SEC's willingness to approve foreign investments does not, however, obviate the need for energy legislation pending in Congress. Some foreign investment structures could raise the issue of self-dealing which would make FERC approval difficult to obtain. In addition, both the House and Senate energy bills would need to be modified to permit investment in foreign projects that involve retail sales.

(e) The Proposals to Amend PUHCA

Senate: On May 21, 1991, the Senate Energy and Natural Resources Committee adopted amendments to remove the Public Utility Holding Company Act's restrictions on non-QF independent power producers. The amendments were adopted as part of a comprehensive energy bill, S. 341, which was renumbered after the Committee completed markup to S. 1220.¹⁰⁸ The provisions approved by the Committee would provide a blanket exemption from PUHCA for companies that own or control Exempt Wholesale Generators ("EWGS"), which are power generation facilities, the output from which is sold exclusively at wholesale. The provisions also enhance state regulatory

107. 1992 SEC Lexis 1571 (1992).

108. National Energy Security Act of 1991, S. 1220, 102d Cong., 1st Sess. (1991).

oversight, define the border between federal and state jurisdiction, and restrict utilities from illegally profiting from their relationships with affiliates. Utilities could own EWGs and QF developers could own EWGs without losing QF status under PURPA. The legislation also includes provisions to enhance state ability to oversee EWG operations, clarify the ability of state commissions to review the prudence of wholesale purchases for rate recovery purposes, and to require review of purchases from EWGs prior to the contract's effective date. In the case of sales among registered holding company affiliates, FERC approval would preempt the state prudence review, except in the case of EWGs. S. 1220 was defeated on the Senate floor in November of 1991 at the close of the First Session of the 102nd Congress.¹⁰⁹

On January 29, 1992, however, the bill's sponsors introduced an energy bill which was identical to S. 1220 with the exception of four sections that were deleted from the bill; Title VII - ANWR; Title III - CAFE; Subtitle D of Title VI - Used Oil; and Subtitle B of Title XIV - WEPCO. The full Senate approved S. 2166 on February 19, 1992.

House: On October 31, 1991, the House Energy and Power Subcommittee approved the House version of the energy strategies bill, H.R. 776.¹¹⁰ As approved by the Subcommittee, independent power producers might apply to the FERC to obtain an exemption from PUHCA, and the FERC was required to exempt from PUHCA persons engaged exclusively in owning or operating plants that generate power exclusively for sale at wholesale. The bill would also implement a new procedure in which the Commission would decide the lawfulness of sales by IPPs. Under the legislation, power sales agreements that resulted in undue prejudice or disadvantage or that result in the granting of undue preference or advantage would be unlawful. It would be unlawful, per se, for a utility to refuse transmission access to prevent an IPP from competing. The bill permitted utility-affiliated IPPs but prohibits sales by an affiliated IPP to its parent. Hybrids would be prohibited as would be conversion of rate-based plants to IPPs.

The House legislation included a number of "savings" provisions related to the PUHCA exemption for IPPs. First, companies that are currently exempt from PUHCA under section 3 would be allowed to acquire and maintain an interest in the business of one or more IPPs without jeopardizing their current exemption.¹¹¹ Second, QF owners would be allowed to acquire and maintain an interest in the business of one or more IPPs without being considered "primarily engaged" in the sale of generation of electricity. Thus, a company which owns interests in both QFs and IPPs will not become subject to PURPA's electric utility ownership restrictions. Third, the bill authorized holding companies that are registered with the SEC under PUHCA to acquire

109. *Id.*

110. Comprehensive National Energy Policy Act, H.R. 776, 102d Cong., 1st Sess. (1991).

111. 15 U.S.C. § 79c (1988).

and maintain an interest in the business of one or more IPPs and finds that such an interest is consistent with the requirements of section 11 of PUHCA.¹¹²

Unlike the Senate bill, the House bill clarified the Commission's power to order wheeling and also required the Commission to mandate transmission access when utilities seek market-based rates or mergers. The legislation clarified which municipal utilities would be covered by the Commission's transmission authority and that, when wheeling was ordered, rates would permit recovery of only those costs necessary to carry out the order. The bill set civil penalties of up to \$25,000 per day for anticompetitive behavior and declared its provisions would not preempt state authority to review IPP finances, environmental protection, or facility siting.

H.R. 776 was marked up by the Energy and Commerce Committee, as well as eight other House Committees, and approved by the House on May 27, 1992.

Before a conference committee can be convened, the Senate must adopt H.R. 776 into its S. 2166.¹¹³ Since H.R. 776 contained tax provisions, the Senate Finance Committee reviewed, and revised, the tax language. The amended bill now must be approved by the full Senate, a process which could prove lengthy. This is because filibusters are threatened by the two Senators from Nevada, with respect to the Yucca Mountain Nuclear Waste Repository and opponents of Senator Jay Rockefeller's (D-W.VA) proposal on funding a coal industry pension and retirement plan.

If the Senate does not pass the bill prior to its July 4th recess, it does not reconvene until the week of July 20th. Shortly thereafter, the Congress adjourns for the August recess not reconvening until after Labor Day. With election year pressures, a conference committee commencing in September may not have enough time to address all the issues which need to be resolved between the two bills.

(f) Energy Taxes

Energy taxes were one of the most prominent deficit reduction options evaluated during the 1990 budget debate. While the 1990 budget compromise ultimately failed to include broad based energy taxes, many observers believe that because of the revenue raising potential of energy taxes, the 1990 debate was merely a preview of things to come and that Congress will eventually return to the pollution and energy area in response to future revenue needs.

Background: In recent years, there has been increased political opposition to new or increased taxes. However, the political opposition to new taxes has never extended to "sin taxes," which are taxes imposed on socially disfavored activities, such as smoking and drinking. Increasing sentiment in favor

112. 15 U.S.C. § 79k (1988).

113. National Energy Security Act, S. 2166, 102d Cong., 2nd Sess. (1992).

of environmental issues and opposition to energy consumption and pollution is making energy and pollution taxes acceptable for similar reasons.

This sentiment was reflected in a number of tax developments during 1990. The "Rostenkowski Plan," announced early in 1990, included \$22 billion over five years from energy related pollution taxes and the House Ways and Means Committee subsequently held hearings on issues associated with environmental taxes. Additionally, the CBO included environmental taxes in its 1990 list of deficit reduction options. By mid-1990, the Bush Administration had embraced an energy tax as its preferred revenue raising option, but the Middle East crisis and the associated increases in energy prices ultimately ended its chance for enactment. However, congressional staff has continued to work on energy taxes as a future deficit reduction option.

Energy and Pollution Tax Options: Pollution and energy tax options under consideration in 1990 included some alternatives of general applicability, such as gasoline excise taxes, which were not of special concern to the cogeneration and independent power industry. However, other tax proposals were directly relevant to the industry. One such proposal was a per ton tax on SO₂ and NO_x. Proposed levels were as high as \$800 to \$900 per ton, and would be in addition to the cost of clean air allowances. Gas fired projects represent the vast majority of projects presently under development and a SO₂ tax would not have had a significant impact on gas-fired projects since the typical 50MW gas project only produces one ton of SO₂ per year. However, other technologies would have been much more significantly affected. For example, a 50 MW coal plant with scrubbers can produce 300 tons of SO₂ per year. A NO_x tax would have had a greater impact on gas projects, depending on the emission control equipment utilized.

Another option which was widely discussed during 1990 was a "carbon tax." Early proposals ranged from \$28 to \$113 per ton of carbon. A \$28/ton tax would equal:

- \$0.45/1000 cubic feet for gas.
- \$3.60/bbl for oil.
- \$17.00/ton of coal.

During 1990, considerable attention was paid to a proposal by Rep. Pete Stark (H.R. 4805), which would phase in a carbon tax starting at \$5/ton, and increasingly ratably over five years to \$ 25/ton. This would equal:

- \$0.08/mcf rising to \$0.40/mcf for gas.
- \$0.65/bbl rising to \$3.25/bbl for oil.
- \$3/ton rising to \$15/ton for coal.

Other forms of energy taxes, such as a BTU tax, have frequently been considered as revenue raising options in recent years. However, the BTU tax has been criticized for its complexity, in light of the broad range of BTU values associated with various types and grades of fuel. This has led some indus-

try observers to predict that a simpler broad-based tax, such as a Kwh tax, may be proposed as a substitute.

The states have also focused on energy taxes to help balance their budgets. In 1991, New York enacted a comprehensive set of energy tax increases for precisely this purpose, and other state and local jurisdictions can be expected to follow suit in the future.

Whatever energy tax option is ultimately selected, the expressed preference of Congress and state legislatures has been to impose the tax as close to the producer level as possible. This is motivated by the ease of collection and by the desire to make the tax as invisible to the public as possible. Unfortunately, this poses a significant risk for cogeneration and IPPs. If the tax is imposed on the fuel purchased by the project, but there is no mechanism to flow through the price increase to the utility, and ultimately its ratepayers, the project will have to absorb the tax. Unfortunately, the price of electricity under most power sale contracts is either fixed or indexed to general increases in inflation indexes. These contracts provide no mechanism to flow through the increased cost to the utility.

Some power sale contracts include an energy price that escalates based on increases in the cost of fuel. Depending on how the contract is written, these contracts could flow through any price increase based on increased fuel costs due to a carbon tax. However, even these contracts would probably provide little or no relief from price increases due to a per ton tax on SO₂ and NO_x. By contrast, electric utilities typically have no comparable restriction on their ability to flow through increased costs.

Some industry members have expressed confidence that state regulatory commissions would provide an avenue of relief from contracts that are made unduly burdensome by new energy taxes. However, as the recent action of the Virginia State Corporation Commission indicates, cogenerators and independent power producers cannot count on state utility commissions to authorize price increases to compensate for such taxes. In December, 1990,¹¹⁴ the Virginia SCC rejected a proposal by independent producers to flow increased environmental costs through to utilities and their ratepayers. Similar responses to proposals to flow through increased energy tax burdens would not be surprising. Accordingly, it will be important for developers to continue to pay attention to legislative developments since energy taxes are likely to remain an attractive deficit reduction vehicle for years to come.

II. JUDICIAL DEVELOPMENTS

A. Backup Power:

In *Gulf States Utilities Co. v. FERC*,¹¹⁵ the D.C. Circuit upheld a ruling by the Commission that a power-producing cogeneration unit and a power-

114. Case No. PUE900029 (1990).

115. 922 F.2d 873 (D.C. Cir. 1991).

consuming unit can constitute one QF for the purposes of certification under PURPA even if separately owned and not adjacent. The power-producing unit would be owned by a joint venture between Fina Oil and Chemical Company and Union Carbide Corporation and would supply thermal and electric energy to Fina's adjacent refinery. The plant would also supply electricity, but not steam, to a Union Carbide plant located 1.7 miles away by means of a private transmission line. Gulf States objected to inclusion of the Union Carbide plant in the QF and Gulf States resulting obligation under PURPA to provide back-up power to the plant.

The court found that the Commission had adequately explained its finding that the Union Carbide plant was an integral part of the cogeneration operation and thus constituted part of the QF. The reasons the Commission gave in support of the integrated nature of the facility were that (1) Union Carbide was a part owner of the producing unit; (2) the Union Carbide plant was in close proximity to the producing unit; (3) the electrical power line linking the two parts of the facility was a private line, indicating that the Union Carbide plant was part of an integrated industrial operation; and (4) Fina and Union Carbide had a longstanding customer/supplier relationship before entering into the cogeneration joint venture suggesting that their relationship served purposes other than the acquisition of QF status. The court noted that, although it had held, in an earlier case,¹¹⁶ QF status did not depend on whether the power-producing unit was owned by the same company which owned the power-consuming unit, there was no reason not to look at the fact of common ownership of the two units, as the Commission did in this case, in determining whether the units constitute an integrated cogeneration operation for the purposes of the PURPA regulations. However, the court conceded that it was not entirely comfortable with the Commission's multi-part test and cautioned that there were limits to how far the Commission could go in granting QF status to cogeneration plants.

III. REGIONAL DEVELOPMENTS

A. *Illinois*

On April 29, 1992, the Illinois Commerce Commission ("ICC") issued a resolution at Docket No. 92-0145 initiating rulemaking which would establish rules for the use of competitive bidding to obtain supply-side resources. ICC staff developed a proposed rule which was the subject of a series of workshops beginning on September 16, 1992. It is anticipated that the informal workshops will result in a proposed rule to be submitted to the ICC in February, 1993 as the basis for the formal rulemaking process.

In July, 1992, the Commonwealth Edison Company issued a request for proposals seeking peaking capacity from all non-utility sources. A pre-bid conference was held on September 9, 1992. Bids are due October 26, 1992. The request for proposals indicated that the utility would entertain proposals for baseload as well as peaking capacity and indicated an interest in projects in which the utility could own an interest.

116. *Puerto Rico Elec. Power Auth. v. FERC*, 848 F.2d 243 (D.C. Cir. 1988).

B. *Massachusetts*

On August 31, 1990 the Massachusetts Department of Public Utilities ("Department") adopted regulations implementing an integrated resource management ("IRM") procedure for the electric utilities subject to its jurisdiction.¹¹⁷ The regulations extended the previously existing solicitation procedures for QF's to include all potential resources including utility generation, independent power producers, and non-utility conservation and load management ("C&LM") programs. Electric utilities, including the host utility, are allowed to participate in the all-resource solicitation. The objective of the regulations is to have all potential generation and C&LM resources evaluated on the basis of the relative benefits and costs of each.¹¹⁸

Under the regulations each electric utility is required to adopt a ranking system to evaluate project proposals 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.¹¹⁹ Environmental externalities are defined as "the value of those environmental damages (or impacts) caused by the project or activity".¹²⁰ The Department has an ongoing proceeding on the subject of environmental externalities.¹²¹

The first IRM solicitation, by the Massachusetts Electric Company, for 10 MW's of demand savings and 200 MW's of supply, was approved by the Department on November 8, 1991.¹²² The Department is currently reviewing the solicitations proposed by Cambridge Electric Company and Commonwealth Electric Company and orders are expected to be issued later this year.¹²³ The following schedule has been established for the other electric utilities.

<i>Electric Company</i>	<i>Filing Date</i>
Western Massachusetts Electric Company	7/1/92
Fitchburg Gas and Electric Company	1/1/93
Boston Edison Company	2/1/93
Eastern Edison Company	4/1/93

C. *Montana*

There are numerous small non-utility generation facilities in Montana, and two projects of major size. The two major non-utility generation projects

117. D.P.U. 89-239, August 31, 1990.

118. *Id.*

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

120. Mass. Regs. Code tit. 220, § 10.02 (1991).

121. D.P.U. 91-131 (pending issuance).

122. D.P.U. 91-114, EFSC 91-24, November 8, 1991. It should also be noted, however, that two electric utilities issued requests for proposals under the old regulations during 1991. Boston Edison Company issued a solicitation on October 11, 1991 with a submittal deadline of January 31, 1991 and Eastern Edison Company issued a solicitation on December 20, 1991 with a submittal deadline of April 15, 1991. The Eastern Edison Company solicitation is limited to QFs.

123. D.P.U. 91-234, EFSC 91-4 (pending issuance).

are the Eureka gas turbine project and the refinery petroleum coke cogeneration project. Both of these projects are in the planning and development stages.

On July 29, 1991, Montana Power Company issued a Request for Proposal ("RFP") for up to 150 MW of supply-side and demand-side management resources. The Notice of Intent was due September 6 and the proposal deadline is December 20, 1991. As of October 1991, over 170 proposals, including about 80 from within Montana, have been submitted.

Montana-Dakota Utilities Co., which serves Eastern Montana communities, has not issued a request for proposals.

D. New York

1. Court Decisions

The Appellate Division upheld a decision of the New York Public Service Commission ("PSC") that additional capacity of a non-utility cogeneration project was not covered by the pricing terms of the original contract for the project.¹²⁴ The developer, Indeck-Yerkes and Niagara Mohawk Power Corporation, executed a 30-year contract for a 49 MW project with cone-like pricing, which was approved by the PSC in June 1987.¹²⁵ In April 1988, the developer informed Niagara Mohawk that the project would actually have a capacity of 53.4 MW. When the utility refused to agree to purchase the increased amount under the pricing set forth in the original contract, the developer petitioned the PSC for a declaratory ruling. The PSC held that the cone pricing formula was no longer a standard offer and that the additional output should be purchased under a new contract with the then-applicable standard offer pricing structures, which were less favorable to the developer.¹²⁶

On appeal, the lower court reversed the PSC's order, but the Appellate Division reversed the lower court's decision. The Appellate Division held that the developer had not expressly reserved the right to expand its output under the terms and conditions of the contract and had even struck from the contract a clause which could have permitted expansion under the same pricing structure. Also, the terms of the contract were interpreted as defining the amount to be purchased as electricity from a project of 49 MW with an annual production of 400,000 MW's. Moreover, the court found that the PSC staff recommendation to the PSC that the contract be approved was based on cal-

124. *Indeck-Yerkes Energy Serv., Inc. v. Public Serv.*, 164 A.D. 2d 618, 564 N.Y.S.2d 841 (App. Div. 1991).

125. *Niagara Mohawk Power Corp. and Indeck-Yerkes Energy Serv., Inc.*, Letter Order (June 15, 1987).

126. *Case 88-E-114, Indeck Energy Serv., Inc.*, Declaratory Ruling (Sept. 14, 1988). The Commission rejected the developer's argument that the increased capacity was due to design modifications that increased fuel efficiency and reduced air pollutant emissions. *Case 88-E-114, Order Denying Petition For Rehearing* (Feb. 28, 1989).

culations applying the contract's pricing structure to the initial 49 MW capacity.

Indeck and Niagara Mohawk subsequently executed a new contract, which was approved by the PSC, which provides for bifurcated pricing, in which each kwh of output is priced proportionally at two rates, the rate specified in the original contract for the original capacity and the rate in the new contract for the additional capacity.¹²⁷

2. PSC Developments

In 1991, the PSC issued decisions establishing standard offer formats for energy-only contracts with a maximum term of twenty years.¹²⁸ The variable rate option priced electricity at the purchasing utility's actual energy-only tariff rate which is updated in rate cases and other proceedings. Three fixed-price formats were adopted, with payments at six cents/kwh over a period sufficient to levelize to the energy-only component of the long-run avoided cost ("LRAC") estimates or of tariff rates and payments at yearly energy-only LRAC rates over the period required for LRAC levelization. The maximum period for fixed prices was set at five years and purchases in additional years would be at tariff rates.¹²⁹ Energy-only contracts are subject to milestones for commencing construction (30 to 36 months from contract execution) and commencing operation (60 months from contract execution) with up to six month-by-month extensions permitted upon posting or forfeiting deposits. The PSC decisions provided for procedures by which energy-only developers could offer capacity to the energy-purchasing utility or to other utilities.¹³⁰

The PSC withdrew the 1990 LRAC estimates, effective September 11, 1991, based on new forecasts that load and fuel prices would be lower and that

127. Case 90-E-0084, Order Approving Contract Subject to Condition (April 30, 1991). Pricing for the new capacity follows Option I of the PSC's Interim Policy, which provides for purchase at the greater of the statutory minimum rate of 6 cents/kwh and Niagara Mohawk's tariff rate. The PSC rejected Niagara Mohawk's proposal to use hourly metering to price the output of 49 MW at the original contract rate and the output of the new capacity at the Option I rate.

128. Case 90-E-0675, Opinion and Order Establishing Power Purchase Contract Policies and Procedures, Opinion No. 91-2 (Feb. 25, 1991); Case 90-E-0675, Opinion and Order Modifying and Clarifying Power Purchase Contract Policies and Procedures, Opinion No. 91-2(A) (July 15, 1991). The PSC required utilities to establish bidding programs for long-term capacity purchase contracts and to enter into contracts with non-bidders and losing bidders at energy-only rates, without a guaranteed capacity payment. However, avoided transmission capacity credits are to be paid to projects interconnecting below transmission voltages. Energy-only contracts following the standard formats would be presumed prudent. However, utilities were permitted to purchase capacity outside of bidding, subject to prudence review.

129. Most non-utility projects in New York qualify for the statutory minimum rate as well as for avoided cost rates under PURPA. However, the PSC decided that the fixed price 6-cent levelized formats need not be offered to federal-only QF projects, which were entitled to fixed prices for a 5-year period without levelization.

130. Developers with fixed price contracts levelized to tariff rates would be required to repay the tracking account. Developers with fixed price contracts levelized to LRACs would be required to repay the tracking account and compensate the energy-purchasing utility for the potential difference between the contract price and greater avoided costs at the time of delivery.

demand-side management and non-utility generator resources would be higher than previously expected.¹³¹ Also, the PSC expressed concern that several large-scale energy-only projects were offered at the 1990 LRACs and that the utilities had received proposals for 7000 MW of energy-only resources at 1990 energy-only LRAC rates. An order withdrawing the 1990 LRACs on a permanent basis was issued early in February.¹³² Only fully executed contracts on file as of September 11, 1991, were entitled to pricing based on the 1990 LRACs and grandfathering for contracts under negotiation at that time was denied. An exception was granted to developers of projects 2 MW or less in size, who were given 60 days from February 10, 1992, to conclude negotiations for contracts based on the 1990 LRACs.¹³³ The PSC denied a request to exempt renewable-fuel projects from the withdrawal of the 1990 LRACs.¹³⁴

The February order revised security provisions for the levelized price standard format energy-only contracts that were established last year in response to the lower LRAC estimates submitted in the current LRAC proceeding. Last year the PSC determined that security in the form of a second lien on the project would be adequate to insure repayment of tracking accounts. In the February decision, the PSC found that the levelization period for standard format contracts would be much longer and the accumulated tracking account amounts correspondingly higher at the end of the 5-year period of fixed prices than previously expected. Accordingly, the PSC ruled that firm security should be required for the difference between the second lien security value and the amount accumulated in the levelization tracking account.¹³⁵ The value of the second lien security, and thus the amount of firm security required, would be updated annually during the levelization period.¹³⁶

The PSC also determined that energy-only contracts using the 6-cent/kwh rate should include a provision which would be triggered by the repeal of the statutory minimum rate by the New York Legislature. The contract term would provide for termination of the 6-cent/Kwh rate, substitution of the purchasing utility's energy-only tariff rate and amortized repayment of the tracking account against the tariff.

A proceeding to set administratively-determined LRAC estimates is going on at this time.¹³⁷ The PSC staff filing indicates that new long-term

131. Case 91-E-0237 and Case 89-E-127, Order Withdrawing 1990 Long run Avoided Cost Estimates and Requesting Comments (Sept. 18, 1991). The 1990 LRAC estimates would not be available for ongoing negotiations, but would apply only to fully executed contracts filed with the PSC.

132. Cases 91-E-0237 and 89-E-127, Order Withdrawing 1990 Long-Run Avoided Cost Estimates On A Permanent Basis (Feb. 10, 1992).

133. Developers of small projects were permitted 15 days after the close of the 60-day grace period to demonstrate that a fully developed project proposal had been submitted to the utility and that the delay was caused solely by *bona fide* issues in dispute. *Id.* at 7, n.1.

134. *Id.* at 11-12.

135. *Id.* at 10.

136. *Id.*

137. A recommended decision of the administrative law judge is expected February 15, 1992, and a PSC decision is expected in the spring of 1992.

capacity resources will not be needed on a statewide basis until 2007 and that statewide avoided energy costs are likely to be lower during the 1990s than calculated under the 1990 LRACs. Staff estimates, submitted January 27, 1992, show 5-year levelized avoided energy costs ranging from nearly 3 cents/kwh to about 4 cents/Kwh for the seven investor-owned utilities in New York. These estimates may be revised before they are sent to the PSC for approval. Several issues raised in the LRAC proceeding have been deferred for further proceedings including revisions to avoided environmental externality cost estimates. A final decision by the PSC is expected during the spring of 1992. A proceeding to determine the policies and procedures for setting rates based on utility tariffs for short-term avoided energy and capacity costs is expected to begin at that time.

Rochester Gas and Electric Company and New York State Electric & Gas Corporation ("NYSEG"), which had solicited capacity under PSC-approved bidding programs, canceled their auctions before selecting winning bidders. NYSEG's decision was challenged and is the subject of an ongoing administrative proceeding.¹³⁸

E. Pennsylvania

1. Regulatory Developments

(a) QFs File Petitions Against Penelec

Three developers of proposed cogeneration facilities have filed motions with the Pennsylvania Public Utility Commission ("PUC") against Pennsylvania Electric Company ("Penelec"). The developers include: American Power Corporation and CMS Generation Company, Bethlehem Steel Corporation and Hadson Power Systems (now LG&E Energy Systems), and Cambria Partners, consisting of Foster Wheeler Power Systems, Incorporated, Enprotech Corporation, and WPEC, Incorporated. All three groups of developers are alleging that Penelec has violated its obligations under PURPA by refusing to negotiate with the developers for the purchase of associated capacity and energy from the proposed facilities. The moving parties filed direct testimony in the proceeding¹³⁹ on January 31, 1992 and hearings will take place the first week in April, 1992.

(b) Met-Ed's Competitive Bid Finally Approved

After a long series of hearings and settlement negotiations, the PUC approved Metropolitan Edison's ("Met-Ed") competitive bidding proposal.¹⁴⁰ On January 31, 1992, Met-Ed issued its RFP for 200 MW of generation projects to be in commercial operation and capable of delivering electric power to the company not later than December 31, 1997. Potential bidders

138. Case 919-E-1005, Case 91-E-1082, Notice Requesting Comments (Nov. 6, 1991).

139. Bethlehem Steel Co., Docket No. P-870235 (filed July 8, 1987).

140. Metropolitan Edison, Docket No. 890366 (1989).

are requested to return a Notice of Intent form within 20 days of receipt of the RFP and bids are due on June 29, 1992. The competitive bidding order was somewhat complicated by other PUC orders directing Met-Ed to enter into contracts for 100 MW and 200 MW from cogeneration projects to be developed by Ahlstrom Development Corporation¹⁴¹ and Air Products & Chemicals,¹⁴² respectively. The PUC pointed to Ahlstrom's steam host, the Scranton District Heating System, that is desperately in need of inexpensive steam, as a primary reason for granting the petition. The PUC also pointed to the canceled 80 MW Oxbow QF project as a reason that Met-Ed should purchase the power from the Ahlstrom project. Finally, the PUC ordered Met-Ed to enter into a contract with Air Products & Chemicals if the developer received a \$75 million DOE Clean Coal Grant. Air Products argued that it needed the power purchase agreement to be eligible to receive the grant.

(c) GPU/DOE Transmission Line

General Public Utilities ("GPU") filed a request for regulatory approvals of agreements between itself and DOE. The agreements between the two utility parents propose construction of a 1,500 MW transmission line. Under the proposal, GPUs operating companies will own two thirds of the line and Duquesne Light will own one third. Each of the operating companies (Penelec, Met-Ed and JCP&L) will be responsible for one third of the cost of the transmission line. A PUC Administrative Law Judge has issued a recommended decision that the PUC approve the agreements. According to the agreements, 500 MW of the 1,500 MW of capacity will be used by Met-Ed, however, the remaining capacity is supposed to be available for purchase by utilities, QFs and IPPs.

2. Court Cases

In *Armco Advanced Materials Corp. v. Pennsylvania Public Utility Commission*,¹⁴³ the Pennsylvania Commonwealth Court ruled that a utility's avoided costs are to be determined at the time a legally enforceable obligation exists between a QF and a utility. The court defined a legally enforceable obligation as of the date that a QF acts by doing everything within its power to create a legally enforceable obligation "either by tendering a contract to the utility or by petitioning the PUC to approve a contract or compel a purchase, and only an act of acceptance remains to establish the existence of a contract."¹⁴⁴ Previously, the PUC had established the time of commencement of serious negotiations between a QF and a utility as the time that locked in a utility's avoided cost.

The Pennsylvania Supreme Court granted the PUCs petition for allow-

141. Community Central Energy Corp., Docket No. P-910514 (1991).

142. Air Products and Chemicals, Inc., Docket No. P-910549 (1991).

143. 579 A.2d 1337 (1990) [hereinafter *Milesburg II*].

144. *Id.* at 1347.

ance of appeal of *Milesburg II* on November 19, 1991 as well as reinstating the PUC's prior "serious negotiations" standard as the time frame for locking in a utility's avoided costs.

3. Legislative Developments

On June 29, 1991, several members of the Pennsylvania General Assembly introduced House Bill No. 1844. The Bill's stated purposes are to: (1) provide certainty with respect to the need of electric utilities for additional generating capacity; (2) promote increased employment and other economic opportunities in this Commonwealth; (3) resolve potential ambiguities with respect to avoided cost determinations; (4) ensure that qualifying facilities have adequate and fair access to transmission services; (5) provide a minimum pool of sulfur dioxide allowances for the benefit of qualifying facilities, and (6) increase the Commonwealth's energy independence while encouraging the use of natural resources. It is contemplated that a similar bill will soon be introduced in the Pennsylvania State Senate.

F. Texas

The Supreme Court of Texas ruled against the Texas Public Utility Commission and held that both state and federal regulations permit a utility purchasing power from a cogenerator to recover from its ratepayers payments in excess of its avoided cost.¹⁴⁵ The case arose out of the sale by Gulf States Utilities Company of two of its electrical generating plants to a joint venture among three of Gulf States' largest industrial customers and Gulf States (at a 1% interest). Gulf States would operate the plants and purchase the entire electric output at a price calculated by a contractual formula that could result in a purchased power rate greater than avoided cost. In return, the industrial customers would continue as Gulf States customers. The generating plants were certified by the FERC as a QF. The PUC held that, under its regulations, Gulf States could not recover anything above avoided cost. The court disagreed, and held that the PUC's regulations do not impose a ceiling on the amount a utility can contract to pay for a QF's power or limit the amount the utility can recover from its ratepayers under such arrangements. Recognizing that one section of the PUC's regulations provided that rates for purchases of energy and capacity from a QF shall not exceed avoided cost, the court determined that this provision does not apply to contractual arrangements between utilities and QFs. The court also held that federal regulations do not grant the PUC any more authority to regulate negotiated purchases than do the state regulations.¹⁴⁶ The court ordered the PUC to allow Gulf States to recover purchased power payments in excess of its avoided cost in future rate proceedings if it establishes to the PUC's satisfaction that the payments are reasonable and necessary expenses.

145. *Public Util. Comm. v. Gulf States Util. Co.*, 809 S.W.2d 201 (Tex. 1991).

146. The court found that "the interstate activities of GSU clearly bring it within the reach of the federal regulations." *Id.* at 208.