Report of the Committee on Electric Utility Regulation

In 1991 the Federal Energy Regulatory Commission (FERC or Commission) continued its efforts to restructure the electric utility industry, emphasizing market-based pricing of wholesale power transactions and transmission access and pricing.

I. Wholesale Power Transactions

The FERC continued its attempts to encourage the development of a competitive generation market by approving, under certain circumstances, wholesale sales of power at market-based prices. After several years of case-by-case development of its policies, the FERC requires stringent proof that the seller seeking to charge market-based rates either lacks market power in the relevant geographical generation and transmission markets or has mitigated that market power by offering transmission access on its system to potential competitors. This same showing must be made for "affiliate transactions," involving all sales by power producers that are owned or controlled by a FERC-jurisdiction utility. Affiliate transactions geographically near the parent utility's electric system raise additional concerns of potential preferential treatment.

In two 1990 affiliate transactions, *TECO Power Services Corp.*[1] and *Terra Comfort Corp.*,[2] the FERC rejected proposed market-based rates because: (1) the rates appeared preferential; and (2) neither the affiliate nor the parent utility had offered transmission service to potential competitors. In *Enron Power Enterprise Corp.*,[3] the Commission described its standard for review of long-term power sales and market based rates as:

> (1) whether the seller or any of its affiliates is a dominant firm in the sale of generation services in the relevant market; (2) whether the seller or any of its affiliates owns or controls transmission facilities which could be used by the buyer in reaching alternative generation suppliers; or, whether such sellers or affiliates have adequately mitigated their ability to block the buyer in reaching such alternative suppliers; and (3) whether the seller or any of its affiliates is able to erect or otherwise control any other barrier to entry. We have also analyzed whether there is evidence of potential abuses of self-dealing or reciprocal dealing.[4]

The FERC decided two other cases involving market-based rates in late 1990, one an affiliate transaction[5] and the other a non-affiliate sale.[6]

In 1991 the FERC issued three orders concerning market-based rates. Two of those orders shed further light on the issue of affiliate transactions.

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1. 52 F.E.R.C. ¶ 61,191 (1990).
2. 52 F.E.R.C. ¶ 61,241 (1990).
3. 52 F.E.R.C. ¶ 61,193 (1990).
4. *Id.* at 61,708.
5. Commonwealth Atlantic Ltd. Partnership, 51 F.E.R.C. ¶ 61,368 (1990).
6. Dartmouth Power Assocs. Ltd. Partnership, 51 F.E.R.C. ¶ 61,368 (1990).

A. *Affiliate Transactions*

1. *Nevada Sun-Peak Ltd. Partnership*

Nevada Sun-Peak,[7] a subsidiary of Million Energy, in turn an affiliate of SCEcorp, proposed market-based rates for the sale of 210 megawatts of peaking capacity to Nevada Power Company from combustion turbines constructed by Sun-Peak in Nevada Power's Sunrise station. The FERC rejected the proposed rates because Sun-Peak had not demonstrated that it lacked market power in generation.[8] In essence, the FERC required Sun-Peak to show either that its purchaser, Nevada Power, had considered alternative suppliers (other than self construction, which it had analyzed) or that Sun-Peak had competed with actual alternatives available to Nevada Power.

Because it appeared that Nevada Power had looked no further than Sun-Peak to meet its urgent need for power, the FERC rejected Sun-Peak's filing even though the Nevada Commission had determined that Sun-Peak was Nevada Power's least cost alternative.

The FERC stated that a formal solicitation by Nevada Power might have sufficed to meet FERC's competition requirement. The FERC did not state whether it would approve the rates if Sun-Peak were the only supplier that responded to such a solicitation.

In its order on rehearing[9] the Commission determined that Sun-Peak had submitted sufficient information to establish that the contract's rates (which had not been changed from the earlier, rejected application) were acceptable under traditional cost of service pricing principles, and declined to address Sun-Peak's arguments seeking to justify the rates as market-based.

2. *Boston Edison Co. re: Edgar Electric Energy Co.*

In this second case, Boston Edison Company and its affiliate, Edgar Electric Energy Company,[10] filed market-based rates for the sale of capacity and energy from Edgar Energy's 306 megawatt combined cycle generating unit to Boston Edison. The FERC rejected the proposed rates (without prejudice) despite an attempted extensive benchmark justification of the rates provided by Boston Edison in its filing.

Boston Edison supported the proposed rates as its least cost alternative by comparing the Edgar sale to four different benchmarks: (1) contracts Boston Edison had negotiated with fifteen different suppliers over the previous three years; (2) proposals from forty-eight PURPA[11] qualifying facility projects (QFs) in response to Boston Edison's 1989 request for proposal; (3) thirty-four QF and independent power producer (IPP) contracts negotiated by other Massachusetts utilities between 1984 and 1989; and (4) rates charged by two IPPs which had received FERC approval.[12] The FERC agreed that

7. 54 F.E.R.C. ¶ 61,264 (1991).
8. *Id.* at 61,771.
9. 55 F.E.R.C. ¶ 61,085 (1991).
10. Boston Edison Co. *re*: Edgar Electric Energy Co., 55 F.E.R.C. ¶ 61,382 (1991).
11. Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et seq.* (PURPA).
12. 55 F.E.R.C. ¶ 61,382, at 61,162-3.

benchmarks can be useful, but are not dispositive in supporting a market-based rate. However, the benchmarks must be contemporaneous with the proposed transaction, must be similar in terms and conditions, and must themselves be shown not to have resulted from exercises of market power by the sellers. Boston Edison's benchmarks apparently failed to meet these criteria. Rather, the FERC preferred a formal solicitation by the purchaser as a demonstration that the seller lacked market power, that actual competitors had access to the purchaser, and that the seller affiliate were not guilty of unlawful self dealing.

For the first time the Commission explained the criteria that must be met before it will approve market rates for affiliate transactions. The FERC must ensure that the affiliated buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and non-price terms. The Commission gave examples of three ways in which market value, and therefore the lack of potential for self dealing, can be demonstrated. The first involves evidence of "direct head-to-head competition" between the affiliated seller and competing non-affiliated suppliers either in a formal solicitation or in an informal negotiation process. If this type of evidence is to be used, the Commission required that there must be:

> . . . assurance that (1) the solicitation or negotiation was designed and implemented without undue preference for the affiliate, (2) the analysis of the bids or responses did not favor the affiliate, particularly with respect to evaluation of nonprice factors, and (3) the affiliate was selected based on some reasonable combination of price and nonprice factors.[13]

A second method would be evidence of the:

> . . . prices which nonaffiliated buyers were willing to pay for similar services from the Edgar project. This second type of evidence is credible only to the extent that the nonaffiliated buyers are in the relevant market as the purchaser, and are not subject to market power by the seller or its affiliates.[14]

Finally, the FERC stated that "Boston Edison could offer benchmark evidence which shows the prices, and terms and conditions of sales made by nonaffiliated sellers." Such "evidence could include purchases made by Boston Edison itself, or by other buyers in the relevant market." The Commission also identified credibility considerations of such evidence: ". . . whether the benchmark sales are contemporaneous and whether they are for similar services when compared to the instant transaction." The Commission further explained that it would consider whether the benchmark sales in the relevant market reflect exercises of market power by the seller or its affiliates. The Commission concluded that a comparative analysis of the type offered by Boston Edison, because of a variety of complications, ". . . will be more extensive than a standard cost analysis (which does not consider the buyer's alternatives) or market power analysis (which does not compare prices to those of competitors)."[15]

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13. *Id.* at 62,168.
14. *Id.* at 62,168-69.
15. *Id.* at 62,169.

B. *Independent Transactions*

In a letter order dated July 5, 1991,[16] the FERC approved market-based rates for a twenty-year, 95 megawatt sale of power to Orange and Rockland Utilities from a 150 megawatt project to be developed by Wallkill, a partnership formed for the project by a joint venture between Bechtel Generating and Pacific Gas and Electric Co. The Commission's letter was brief, without comment or discussion. This was the first case in which the FERC issued a letter order to approve an IPP's request for market-based rates.

C. *Transactions Involving Traditional Utilities—Western Systems Power Pool*

On April 23, 1991, the FERC issued an order accepting, subject to certain modifications, the application of the Western Systems Power Pool (WSPP) for permanent status.[17] The FERC had initially approved WSPP effective May 1, 1987, as a two-year experiment in market-based pricing (up to a FERC-approved cap) for short-term power transactions and associated transmission service. The pool featured an electronic bulletin board available to all members on which proposed transactions were posted daily. The FERC twice extended the pool for a total of two years.[18]

The WSPP filed its application for permanency on January 2, 1991, submitting a new agreement which was similar to the agreement which had been the basis for the pool's four-year test. The permanent WSPP agreement, subscribed to by forty-two member utilities: (1) confined pool transactions to one year or less, (2) provided membership to IPPs, while QFs were admitted only if they waived their PURPA guaranteed prices; (3) asked FERC to pre-grant approval for a member to withdraw on thirty days notice; and (4) included a truly unique feature, Exhibit C, which provided principles for long-term firm transmission service.

Exhibit C committed the member utilities (but not IPPs or QFs) to provide cost-based, long-term transmission service to each other for a demonstrated long-term firm system power requirement and a matching resource. Exhibit C also called for disputes to be resolved through binding arbitration. Exhibit C was intended to provide the justification for the FERC to allow the pool to retain market-based pricing for pool transactions.

The FERC's April 23 order conditionally accepting the WSPP and its June 27, 1991, order on rehearing[19] allowed the WSPP to continue, but without market-based rates. Instead, the FERC established pool-wide cost-based ceilings for all transactions, and allowed the members to withdraw Exhibit C in its entirety because, having in FERC's view failed to adequately mitigate market power, Exhibit C was no longer necessary. The FERC also required the pool to admit QFs as long as they waived their avoided cost price entitle-

16. Wallkill Generating Co., L.P., 56 F.E.R.C. ¶ 61,067 (1991).
17. Western Systems Power Pool, 55 F.E.R.C. ¶ 61,099 (1991).
18. Western Systems Power Pool, 38 F.E.R.C. ¶ 61,242 (1987), and two extension orders 47 F.E.R.C. ¶ 61,121 (1991) and 50 F.E.R.C. ¶ 61,399 (1990).
19. Western Systems Power Pool, 55 F.E.R.C. ¶ 61,495 (1991).

ment under PURPA for transactions conducted *within* the WSPP, and granted the right for members to withdraw from the pool upon thirty-days' notice.

In August 1991 certain environmental, consumer and public power interests[20] filed petitions for review of FERC's orders in the U.S. Court of Appeals for the District of Columbia Circuit challenging, *inter alia*, FERC's requirement that QFs waive their PURPA pricing rights for transactions within the WSPP as a condition for pool membership, and the justness and reasonableness of FERC's imposed cost based ceilings. A number of interventions were filed in those now-consolidated proceedings, including several by members of the WSPP and the WSPP itself. The case is still pending.

II. TRANSMISSION ACCESS AND PRICING

A. *Mergers*

The Commission issued orders in 1991 in three mergers. Their principal significance lies in the Commission's views of transmission access and mitigation of potentially increased market power brought about by the consolidation.

1. *Northeast Utilities Service Co.*

In an August 9, 1991, order, the FERC approved, with conditions, the merger of Northeast Utilities (NU) and Public Service Co. of New Hampshire (PSNH).[21] The Commission found that an unconditioned merger likely would have serious anticompetitive consequences. The merged company's expanded control over key transmission interfaces and corridors would allow it to limit access by other New England utilities to important alternative supply sources, thereby isolating various utilities from power suppliers located both within and outside New England. The Commission also concluded that the merged company would have increased market power in short-term bulk power markets. The Commission further stated that NU's substantial inventory of excess generating capacity would give NU the incentive to block the sale of competing sources of short-term bulk power services, and, to the extent NU's resources are not the lowest cost resources that otherwise would be available, the result would be higher electricity prices for New England consumers.

The order discussed: (1) NU's proposed reservation of transmission capacity for its native load; (2) NU's commitment to construct new facilities to provide transmission service; (3) cost responsibility for such upgrades; (4) opportunity-cost rates; and (5) the practice of negotiating transmission contracts on a case-by-case basis as opposed to a transmission tariff.

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20. Environmental Action and Consumer Fed'n of America v. FERC, No. 91-143 (D.C. Circuit filed August 23, 1991) and Wisconsin Public Power, Inc. Sys. v. FERC, No. 91-1404 (D.C. Circuit filed August 23, 1991).

21. Northeast Util. Serv. Co. (*re* Pub. Serv. Co. of New Hampshire), 56 F.E.R.C. ¶ 61,269 (1991).

a. Reservation of Transmission for Native Load

NU offered to make available transmission capacity over its tielines to New York in excess of what it needed to import economy energy for its native load and to enter into additional commitments only to the extent the transmission was not needed for economy imports. Although providing demonstrable evidence of historic use of those lines for economy imports, NU proposed to determine its future needs based on projected future use of the interties.

The FERC rejected NU's proposed set-aside of intertie capacity for economy uses unless the capacity was needed for a reliability purpose (in which case it could be used even for non-firm economy transactions). The FERC asserted, as it had in the *PacifiCorp* merger decision, that "when system constraints occur, firm transmission service should be accorded priority over non-firm service, even if the latter would otherwise benefit native load customers."[22] Thus, the FERC refused to recognize a priority based solely on the economic interests of NU's native load customers.

b. Construction of New Facilities and Upgrades

As part of its merger proposal, NU undertook a conditional obligation to construct new facilities or upgrades to its system as needed to provide transmission service requested by third parties so long as the customer agreed to pay the costs of the upgrade and NU received all necessary regulatory permits and approvals. The FERC generally endorsed charging wheeling customers for the costs of upgrades they cause but left to future cases the issue of upgrade causation.

Each time a transmission customer is denied service by NU, it may file a complaint at the FERC. If NU's response is that there is an "immutable constraint" (*i.e.*, a transmission constraint that cannot be overcome, due to regulatory objection or otherwise), the FERC will hold a technical conference, the participants being all involved state utility commissions, FERC staff, and both parties. The FERC will hear each participant's views giving "substantial weight" to the agreement by all state commissions that there is an immutable constraint. If the FERC agrees that there is an immutable constraint, it will then order the appropriate allocation of existing capacity. Only if the provision of wheeling service over existing facilities would adversely affect reliability of service to NU's native load customers would NU be categorically relieved of the obligation to provide service.

This approach differs from the *PacifiCorp* order in which the Commission ordered that service be provided even if the state commission fails to grant the permits and approvals necessary for new construction, and further ordered that the merged company must absorb the impacts of regulatory action to the detriment of its native load customers. Under the *NU* order, the FERC may

22. *Id.* at 62,020.

order on a case-by-case basis that NU retain existing capacity, that capacity be split between NU and the customer, or that the customer should get the capacity needed for its requested service.

c. Cost Responsibility of New Facilities

NU's merger proposal required wheeling customers to make a pro rata contribution to the cost of transmission upgrades needed to provide service to them, making these customers responsible as a group for these marginal transmission costs. NU agreed to cap wheeling customers' upgrade costs to facilities identified at the time of the wheeling request. The Commission ruled that parties requesting wheeling service should be responsible for the cost of transmission upgrades necessitated by them, but it could not identify how this general principle would be applied in all circumstances.

The FERC generally accepted NU's proposed "but-for" test for allocating the costs of upgrades. When the upgrades would not be needed but for the requested wheeling service, the customer would pay the costs. The FERC stated that, as a general rule, incremental pricing and cost responsibility for upgrades needed to provide transmission service is just and reasonable. However, before allocating costs to a customer, NU must demonstrate that providing the requested service will degrade reliability on its system unless the upgrade is made. NU will bear the burden of proof on the issues of reliability, the specific upgrades needed, the cost of those upgrades, and the allocation of all or a portion of those costs to the customer.

Finally, NU had offered as part of its merger proposal to provide a good faith estimate of the costs of the upgrades needed to provide a requested service. The FERC agreed that cost certainty was important to wheeling customers and that NU's estimate would constitute a cap on costs. Accordingly, NU must estimate its costs (including contingencies) and must absorb any cost overruns—unless it can prove the overrun resulted from unanticipated circumstances beyond its control.

d. Opportunity Costs

NU had previously recovered opportunity costs in its rates for firming up non-firm transmission service. Opportunity costs, as defined in the FERC's order, include the lost benefits of economic purchases foregone by NU to provide firm transmission service to non-firm wheeling customers. NU charges such costs for non-firm transmission customers in lieu of interrupting their service when NU would use the same capacity for its economy purchases. The FERC did not reject the justness and reasonableness of such rates, but noted that NU's conditional obligation to build might eliminate the need for recovery of such costs. The FERC said it would decide the justness and reasonableness issue when NU files a rate schedule to recover those costs.

The Commission distinguished NU's opportunity costs concept from the one rejected in the *PacifiCorp* order, noting that NU proposed to charge this rate only for non-firm service, at the election of the customer, whereas PacifiCorp attempted to impose those costs on firm service. Under NU's proposal, a customer receiving non-firm transmission service could elect to pay opportunity costs to avoid curtailment.

On December 10, 1991, FERC issued an order in the *NU* merger docket (and other related NU dockets) setting oral argument on the issue of opportunity cost pricing for transmission service.[23] This order is discussed in subsection II.B., *infra*.

e. Case-By-Case Contract Negotiations v. Tariffs

Several intervenors asserted that NU's practice of negotiating contracts for transmission service on a case-by-case basis creates uncertainty about the terms and availability of transmission service and allows NU to negotiate "take it or leave it" terms by insisting on a customer's acquiescence before agreeing to provide service. Those intervenors argued that NU's practice places transmission customers at a competitive disadvantage and is harmful to the public interest. The Commission agreed and ordered NU to file a transmission tariff for service up to the longer of twenty years or the life of the customer's power supply agreement.

2. *Kansas Power & Light Co.*

By its January 30, 1991, order, the Commission set for hearing the application of Kansas Power & Light Co. (KP&L) and Kansas Gas & Electric Co. (KGE) for approval of their merger.[24] However, before hearings commenced, on May 20, 1991, the companies filed an offer of settlement. In that offer the companies committed, *inter alia*, to certain transmission service obligations and included in the filing *pro forma* firm and non-firm transmission service schedules which would be filed after the merger closed. These schedules provided for both firm and non-firm transmission at cost-based rates. The offer of settlement was contested.

On September 10, 1991, the FERC approved the settlement.[25] The Commission found that the transmission service schedules will provide non-discriminatory, cost-based transmission access within and through the KP&L and KGE systems, and that requests for transmission service will be promptly handled.

3. *UtiliCorp United, Inc.*

The Commission approved Utilicorp's acquisition or lease of all of Centel Corporation's electric properties without hearing.[26] Centel's property consisted of non-contiguous electric divisions located in Colorado and Kansas,

23. Northeast Util. Serv. Co., et al., 57 F.E.R.C. ¶ 61,340 (1991).
24. 54 F.E.R.C. ¶ 61,077 (1991).
25. Kansas Power & Light Co., 56 F.E.R.C. ¶ 61,356 (1991).
26. UtiliCorp United, Inc. and Centel Corp., 56 F.E.R.C. ¶ 61,031 (1991).

while Utilicorp's electric division, also non-contiguous to either of Centel's, is located in Missouri. The acquisition would not result in any direct ties between the three divisions, and they would remain physically separate. The entities were also relatively small and did not own or control any competing transmission paths. For these reasons, the Commission concluded that a combined UtiliCorp-Centel operation would not attain any greater market power.

B. Opportunity Cost Pricing and Service Priority

In its *NU* merger decision, the Commission deferred for further consideration the question of whether and how NU would be allowed to include in its transmission rates a component designed to compensate it for opportunity cost. This issue received heightened attention because of a speech by FERC Chairman Martin Allday to the American Bar Association on August 13, 1991, only four days after the August 9 *NU* merger decision, in which he advocated a policy favoring third-party firm transmission over the transmission owner's non-firm transactions benefitting the owner's native load customers, regardless of relative value.

According to the Chairman:

> What is at issue here goes beyond reliability-related use of transmission. The proponents of these arguments would give higher priority to the transmission owner's non-firm transactions, than they would give to third-party firm transaction, on the basis that it economically benefits native load.
>
> In the past, these arguments made sense. But today, when we have regional instead of local markets, and when we have an emerging competitive generation market, that is no longer the case. . . .
>
> It's no longer true that a particular utility's native load customers deserve special treatment, to the detriment of someone else's native load customer. After all, everybody is somebody's native load customer. Every third-party transmission transaction is meant to benefit a native load customer somewhere on the interconnected grid. If we really want to create competitive markets, we have to take a broader perspective.

Against this backdrop, on December 10, 1991,[27] the FERC issued an order setting for oral argument the issue of opportunity cost pricing for transmission. Attached to the order was a FERC staff analysis of the issue. The staff paper proposed that, in certain circumstances, native load ratepayers of the transmitting utility must be made whole when the utility incurs opportunity costs in order to undertake a transmission transaction. This is a significant deviation from the original NU merger decision, which had little discussion of the economic interests of native load customers.

The staff analysis would permit recognition and recovery of opportunity costs only when transmission is constrained. In such cases "[b]ecause the Federal Power Act relies (in large measure) upon the voluntary provision of transmission service,"[28] the utility would not otherwise provide the service. Accordingly, the staff proposes that the Commission accept opportunity cost pricing when a utility: (1) accepts an obligation to provide firm transmission service out of existing capacity (including the right to permit the wheeling

27. 57 F.E.R.C. ¶ 61,340 (1991).

28. *Id.*, attachment B.

customer to broker capacity); (2) accepts an obligation to build new facilities; (3) adopts a validation process to ensure that opportunity costs are real; and (4) accepts a cost cap pursuant to which opportunity costs would not exceed the incremental cost of building transmission to relieve the constraint.

The staff analysis also contended that opportunity cost pricing would relieve the need for any "immutable constraint" procedures to allocate capacity. Oral argument was held on January 8, 1992.

C. *Open Access Tariffs*

On August 2, 1991, Entergy Services, Inc. acting on behalf of its operating affiliates[29] requested the FERC to authorize it to sell capacity at market-based rates, and in connection with the request submitted open access transmission tariffs for each of the operating companies to provide access to Entergy's integrated transmission system. The tariffs make firm and non-firm transmission service available to all electric utilities, as defined in the tariffs, including IPPs and QFs that agree to waive their PURPA right to make sales at avoided cost rates in transactions for which they seek transmission service.

Under the tariffs, rates for firm transmission service are based on the embedded cost of each energy operating company's transmission system, with non-firm transmission service provided at a negotiated rate up to one-third of the total net savings associated with the transaction. When power is transmitted over more than the operating company's system, the transmission customer will pay only one rate—the highest rate of any operating company transmitting the power for the customer.

Requests for service are subject to the availability of adequate transfer capability, in excess of that which is required to accommodate: (1) the existing and reasonably forecasted loads of the Entergy System's native load customers; and (2) any existing contractual commitments, any planned generating unit additions, and a block of transfer capability reserved for reliability, regulation, and inadvertent flows. Further, each operating company commits to add facilities to satisfy requests for service, subject only to its ability to obtain the necessary rights-of-way and regulatory approvals. Electric utilities and their affiliates requesting service under the tariffs must commit to provide comparable service to the Entergy System if they own or control transmission facilities.

The filing and its effectiveness are contingent on: (1) the FERC's approval of the transmission service tariffs without modification unacceptable to Entergy; and (2) the FERC's finding that the Entergy System lacks or has adequately mitigated any market power over transmission and any market power in generation in the relevant market areas, so long as the Entergy operating companies satisfy requests for transmission service in accordance with the terms of the transmission service tariffs. Eighteen entities filed motions to intervene with several requesting a hearing. The FERC has not yet acted on the filing.

29. Arkansas Power and Light Co., Louisiana Power and Light Co., Mississippi Power and Light Co. and New Orleans Public Service, Inc.

D. *Environmental Action, Inc. v. FERC*

On August 2, 1991, the U.S. Court of Appeals for the District of Columbia remanded to the FERC for further consideration of the FERC's 1988 and 1989 decisions conditionally approving the merger between PacifiCorp and Utah Power & Light (UP&L).[30] The Commission had to consider its exclusion of QFs and end-use customers from the mandatory firm transmission service PacifiCorp was required to provide as a condition to approval of the merger.

In October 1988, the Commission approved, subject to certain transmission conditions, the merger of PacifiCorp and UP&L.[31] The Commission found that the merged entity would have an increased ability to exercise market power over transmission in the relevant geographic and product markets. Therefore, the Commission required the merged entity to accept as conditions to approval of the merger certain firm transmission obligations designed to remedy future likely anticompetitive effects of the merger. The FERC excluded QFs, end-users, and so-called transmission dependent utilities (TDUs) formed after the date of the merger application from the class of beneficiaries of the transmission conditions. Representatives of those classes petitioned the D.C. Circuit to reverse the Commission. The court's decision remanded to the FERC for further consideration its exclusion of QFs and end-users, and affirmed the Commission's exclusion of newly-formed TDUs.

1. Exclusion of QFs

On appeal, the Commission defended its exclusion of QFs on three grounds, all of which the court rejected. First, the FERC argued that a QF which could access a remote utility through the wheeling conditions, forcing it to buy the QF's power at avoided cost, would achieve an unwarranted competitive advantage. The court chastised the Commission for focusing its antitrust analysis on competitors instead of protection of competition and the interest of consumers. The court then reasoned that an efficient QF would achieve no competitive advantage through being able to sell its power at avoided cost.

> If the QF is less efficient (i.e., has higher costs) than its competitors, its guaranteed ability to sell power only at a price below its cost will not cause its competitors any loss of sleep. If, on the other hand, the QF is more efficient, then the preference it receives is not a threat to, but only a redundant (legal) guarantee of, the competitive (economic) outcome. In fact, the principle effect of the preference seems to be to ensure that large power producers do not discriminate against QFs.[32]

The court went on to say that any advantage a QF receives is in furtherance of policy expressed in PURPA to favor QF sales and that FERC's decision to exclude them from the benefits of mandatory wheeling:

> would effect an administrative repeal of this congressional choice; by definition,

30. Environmental Action, Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991).

31. Utah Power & Light Co., 45 F.E.R.C. ¶ 61,095 (1988), *modified on other grounds on reh'g.*, 47 F.E.R.C. ¶ 61,209 (1989); *supplemented on other grounds*, 48 F.E.R.C. ¶ 61,035 (1989) (Opinion of Nos. 318, 318-A, and 318-B, respectively.)

32. *Environmental*, 939 F.2d at 1061-62 (citation omitted).

> this is not in the public interest. Put otherwise, the PURPA establishes a specific public interest in encouraging QFs by giving them certain rights. This interest may or may not be wholly consistent with the antitrust laws, but being specifically relevant to this case it deserves at least as much consideration as the general interests embodied in the antitrust laws; yet the FERC failed to give it any weight.[33]

The Commission's second argument was that QF transmission access was not needed to mitigate PacifiCorp's market power because QFs would not suffer the same competitive harm as would other suppliers from the denial of transmission access since they, unlike non-QF suppliers, have a guaranteed market for their power. The court rejected this argument, reasoning that the merged company could extract monopoly profits since it could refuse to wheel QF power.

The court gave even shorter shrift to the Commission's third argument, that certain "factual differences" between QFs and other competitors justified their differing treatment. The court noted that the FERC failed to identify any distinguishing features of QFs other than their PURPA preference.

2. Exclusion of End-users

The second issue remanded for the FERC's reconsideration was the denial of access to end-use customers. The FERC offered three justifications to the court (stranded investment, state jurisdiction, and non-responsiveness to effects of the merger) only one of which (stranded investment) the FERC mentioned in its merger opinions.[34] The court found the stranded investment reasoning unsupported by analysis or evidence. The court noted that PacifiCorp could reduce its prices in order to maintain its sales, and would therefore lose no sales and perhaps only insignificant profits. The court addressed the second argument—electric end-use customer bypass is a matter of state concern—merely by noting that on the gas side, the FERC overcame this concern. Finally, the court refused to consider the FERC's third basis for denying retail wheeling. The FERC had argued "that facilitating end-user bypass does not respond to any harm caused by the increase in monopoly power."[35]

The court was also concerned with the FERC's willingness, on the one hand, to allow natural gas end-use customers to bypass their local distribution companies, while on the other hand, barring electric end-users from mandatory transmission access in the PacifiCorp merger in order to prevent electric bypass. According to the court,

> . . . [B]oth the Commission's reasons appeal to be inconsistent with the position it has taken under the Natural Gas Act in the comparable situation involving end-users bypassing a local distribution company. [Citation omitted.] Without more support, and a distinction that justifies the seemingly different approaches that the FERC has taken under two very similar statutes, we cannot accept this foot-

33. *Id.* at 1062.

34. The entire support in the FERC's briefs for exclusion of end-users consisted of one short, conclusory footnote.

35. *Environmental*, 939 F.2d at 1063.

note in full discharge of the agency's obligation to make a reasoned decision.[36]

Two other aspects of the court's decision are noteworthy. First, the court upheld FERC's exclusion of TDU's unborn as of the date of the merger application. Ironically, the industrial end-user that was the principle advocate of retail wheeling, Nucor Steel, was at the time of the court's decision served by a newly-formed municipal utility. The court denied access to the TDU serving Nucor but remanded the question of Nucor's direct access as an end-user. Thus, the FERC failed to justify a refusal to mandate retail wheeling, but adequately justified a limitation on wholesale wheeling. Second, the court affirmed the Commission's refusal to require PacifiCorp to wheel non-firm power.

On December 23, 1991, the FERC issued its order on remand in response to the D.C. Circuit's decision.[37] The Commission decided to reaffirm its exclusion of QFs, but set a "paper" hearing on the issue of end-user access in order to meet the court's concern that there was no evidence supporting the end-user exclusion.

In a detailed opinion, the FERC responded to the Court of Appeals without changing its original holding. First, the opinion noted that PURPA delegated to the FERC a major role in determining how the QF industry was to be developed. The FERC, not PURPA, established the "wheel or buy" rule, under which QF power could be wheeled to a remote utility when all parties agreed. Thus, the FERC argued voluntary transmission, rather than mandatory access, was established as the proper approach for the FERC to encourage the wheeling of QF power. Second, the opinion noted that the encouragement given to QF development in PURPA was not absolute and that the FERC had discretion as to where to draw the line. In particular, PURPA did not include mandatory transmission for QFs, but only the right to be interconnected with the host utility. Third, QFs have the choice of relinquishing QF status and thus becoming utilities with the same transmission access rights as other utilities. Fourth, there was no evidence that any of the anti-competitive conduct on which the transmission access conditions were predicated involved or adversely affected QFs in any way whatsoever. Last, the consumer interest noted by the court is not served by QF access unless the FERC can also monitor the avoided costs of the seven states in which the merged entity operates in order to ensure that the avoided costs did not exceed market prices. Since that is not realistic, there is no practical way to protect consumer interests by allowing QF access.

With respect to retail wheeling, the Commission noted that this issue did not come up in the merger hearings, but was raised solely on rehearing where the Commission held that retail wheeling would jeopardize the ability of the merged entity to recovery its costs and that the issue was best left to state regulation. The court of appeals held that the first basis for excluding retail wheeling was unsupported by the record and that both bases were inconsistent with the existence of end-user bypass of the gas system. The court had

36. *Id.* at 1063.

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

required that the FERC establish a stronger basis for distinguishing between gas and electric retail bypass if its original holding were to stand.

Rather than decide the issue, the FERC solicited more information and requested the parties "specifically identify any anticompetitive impact or impacts resulting from the merger that necessitate retail bypass as a remedy and address how such retail bypass would alleviate any such impact."[38]

Commissioner Trabandt concurred with extended suggestions on how to avoid having retail wheeling imposed by the court on further proceedings.[39] Commissioner Moler had no problem with the treatment of the end-user bypass issue but strongly dissented from the holding excluding QFs from the transmission conditions.[40] In a concurrence that will undoubtedly be quoted in future proceedings, Moler argued that the majority's emphasis on PURPA as the basis for excluding mandatory transmission for QFs was wrong. The FERC's authority to condition a merger, she asserted, derives from Federal Power Act (FPA) section 203,[41] which gives the Commission broad authority to remedy anti-competitive effects in the bulk power market. Moler concluded there was no reason to exclude QFs.

E. Legislative Developments (H.R. 776)

On October 9, 1991, the Energy and Power Subcommittee of the House Energy and Commerce Committee reported out mandatory transmission access legislation to be included in a comprehensive energy bill designated H.R. 776, "Comprehensive National Energy Policy Act."[42] The transmission provisions are patterned after H.R. 2825, introduced June 27, 1991, by Representatives Tauzin (D-LA), Bliley (R-VA), and Boucher (D-VA).[43] H.R. 2825 itself was a more modest version of H.R. 2224, introduced on May 2, 1991, by Representatives Markey (D-MS), Moorehead (R-CA), Dannemeyer (R-CA), Studds (D-MS), and Boucher (D-VA).[44] H.R. 776 would also amend the Public Utility Holding Company Act (PUHCA) to allow electric utility ownership of IPPs without the proscriptions of PUHCA.

The FERC's sole explicit authority to order wheeling is found in FPA sections 211-212. H.R. 776 would expand the FERC's very limited case-by-case authority to order wheeling, but would not address any authority the Commission may have elsewhere in the FPA to do so. Indeed, such authority, to the extent it exists, would be expressly preserved. H.R. 776 would amend existing FPA sections 210, 211, and 212, would add three new sections, (213-215) and make certain associated changes in definitions and enforcement. To summarize these changes, discussed in greater detail below, any interstate wholesale purchaser or seller of power, publicly or privately owned, would be able to obtain FERC-ordered wheeling at cost-based rates under a wide range

38. *Id.* at 62,193.
39. *Id.* at 62,194.
40. *Id.* at 62,196-62,200.
41. 16 U.S.C. § 824(b) (1988).
42. H.R. 776. 102d Cong., 1st Sess. (1991).
43. H.R. 2825, 102d Cong., 1st Sess. (1991).
44. H.R. 2224, 102d Cong., 1st Sess. (1991).

of circumstances from any transmission-owning utility, whether public or private, without regard to the competitive relationship the recipient of the wheeled power may have with the transmitting utility or anyone else.

1. Section 210.

Current FPA section 210 allows the FERC, on application of any electric utility, federal power marketing agency (PMA) or QF, to order the physical interconnection of the applicant's facilities with the facilities of any other QF or electric utility. H.R. 776 broadens the class of applicants to include "any other persons generating electric energy for resale."[45] Since "electric utility" as defined in the FPA includes an IPP (section 3(22)) this amendment appears not to effect any substantive change.

2. Section 211

Existing section 211 limits those who may apply for wheeling orders to electric utilities (which includes IPPs and state agencies), geothermal QFs, and PMAs. H.R. 776 enlarges the class of applicants to include QFs and makes explicit that all publicly-owned utilities are also included. In short, all wholesale purchasers and sellers of power would be able to obtain wheeling orders.

The bill would authorize a wheeling order on a case-by-case basis when the FERC finds such order both to be in the public interest and to satisfy one of six specific criteria (conservation of energy, promotion of efficiency, maintenance of reliability, promotion of competition, enhanced protection of the environment, or remediation of discriminatory or anticompetitive practices).

Although section 211 as amended would not expressly confer on the FERC the authority to order the filing of general transmission tariffs, such authority would probably be implied because of certain language in new section 212(a).

The bill would delete existing section 211(c)(1), which prohibits the FERC from issuing an order unless it finds "that such order would reasonably preserve existing competitive relationships."[46] The FERC's interpretation of that provision has barred orders to wheel to existing requirements customers of the wheeling utility.[47]

3. Section 212

H.R. 776 would do the following: (1) delete in their entirety existing subsections 212(a) and 212(b) and substitute two new subsections relating to limitations on the FERC's authority (section 212(a)) and charges for transmission services (section 212(b)); (2) conform the "savings" clause (section 212(e)) to the new amendments; (3) add a new section 212(g) prohibiting a retail wheeling order under amended sections 211 et seq.; (4) add two new subsections softening the impact of the mandatory access regime on the

45. H.R. 776 102d Cong., 1st Sess. (1991).

46. *Id.*

47. See Southeastern Power Admin. v. Kentucky Util. Co., 25 F.E.R.C. ¶ 61,204 (1983).

Bonneville Power Administration (BPA) (section 212(h)) and the Tennessee Valley Authority (TVA) (section 212(i)); and (5) add a provision intended to prevent so-called "sham transactions" (section 212(j)).

Under new section 212(a) the FERC would be prohibited from issuing an order which would: (1) unduly impair system reliability of any affected utility; (2) unduly impair an affected utility's ability to render adequate service to its customers; or (3) unduly economically disadvantage the customers of the transmitting utility subject to the order.

Proposed new section 212(b) would require the FERC to permit the transmitting utility to recover "all prudently incurred costs . . ." As amended, section 212(b) would also provided that "orders under section 211 or 213 which provide for tariffs of general applicability shall include in such tariffs, rates, terms and conditions for firm and non-firm, and long and short-term transmission services." Thus, although section 211 as amended is silent as to the FERC's authority to order the filing of general tariffs, that authority would probably be implied because of this language in section 212(b).

Existing section 211(c)(4) prohibits the FERC from issuing a retail wheeling order under section 211. New subsection 212(g) would extend that prohibition to transmission tariffs ordered under new section 213.

Proposed section 212(h) applies only to BPA. Using language which can at best be termed ambiguous, the provision insures that H.R. 776 will not supersede the various other federal statutes governing BPA and its generation and transmission systems. The provision also subjects BPA's rates for FERC-ordered transmission, which would probably continue to be determined initially in accordance with BPA's existing procedures, to a just and reasonable standard, but is silent as to whether that standard, in the final analysis, is to be applied by the FERC or BPA. Proposed section 212(i) would prevent the FERC from ordering TVA to wheel power to any distribution customer which has a power supply contract with TVA. Subsection 212(j) would prevent wheeling orders for certain defined "sham transactions."

4. Section 213 (new)

New section 213 requires the FERC to order a transmitting utility to file "tariffs of general applicability for transmission services" when the FERC issues an order permitting the utility (or any affiliate) to sell power at market based rates or merge with another utility. The language, however, is confusing as to whether the open access triggering activities are geographically limited to the service area of the transmitting (or merged) utility. Proposed section 213(b) provides: ". . . the Commission shall issue an order requiring each such transmitting utility (and each affiliate thereof which provides wholesale transmission service in a service area directly affected by the covered sale, merger, or consolidation, as determined by the Commission), to provide [open access] transmission services . . ." Some have interpreted this language to limit the open access triggering activities (market sales, mergers) to the service area of the transmitting utility. However, the reference to "the service area" in section 213(b) appears to operate to limit open access *only* as to the transmitting utility's *affiliate* (and then only if the affiliate owns transmission facilities in the transmitting utility's service area), but *not* as to the *transmitting* utility. This in turn implies that there is no geographic limitation to open access triggering activities as to the transmitting utility. Thus, a California utility's affiliate which makes a market-based sale in New Jersey would require the California utility to provide open access on its system.

5. Section 214 (new)

Section 214(a) would require a transmitting utility to respond to a request for transmission services within thirty days. Section 214(b) imposes certain transmission-related information filing requirements on transmitting utilities. That information "shall be adequate to enable the Commission to carry out the purposes of this section and sections 210 and 211 and to inform potential transmission customers, state regulatory authorities, and the public of available transmission capacity and potential constraints."

6. Section 215 (new)

New section 215 would make any agreement by an IPP to sell power, as determined by the Commission, to be unlawful if it would result in undue preference or advantage or would result in undue prejudice or disadvantage. Denial of transmission access to a competing seller by any purchasing utility shall be deemed an undue prejudice or disadvantage rendering the contract to be illegal. Section 215(c) states that no agreement awarded in a competitive process established by a state commission and which satisfies Commission implementing rules will be unlawful unless "an aggrieved person" shows that the agreement would have the proscribed unlawful effects.

7. Penalties

H.R. 776 would also exempt violations of sections 211-215 from existing FPA enforcement and penalty provisions and instead would put in place specific provisions applicable to the bill's transmission provisions.

8. Definitions

H.R. 776 adds three new definitions to the FPA: (1) "transmitting utility"; (2) "wholesale transmission services"; and (3) "independent power producer." The most significant of these is the definition of transmitting utility. An entity which is a "transmitting utility" is subject to wheeling orders under sections 211 and 213. As defined, a transmitting utility is "any electric utility or [PMA] which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale." H.R. 776 then amends the definition of "electric utility" in existing FPA section 3(22) to make clear publicly-owned utilities are included. The effect of these amendments is to make all privately- and publicly-owned utilities which own transmission facilities used for wholesale transactions potentially subject to wheeling orders under new sections 211 and 213.

The Energy and Power Subcommittee voted, 17-5, to report out this transmission bill. Consideration by the full Committee is expected in spring

1992. Senate Bill 1220, the Senate counterpart of H.R. 776, does not contain any transmission access provisions.

III. Other Pricing and Access Policy Initiatives

A. *FERC Public Conference*

On April 18, 1991, the FERC issued a Notice of Public Conference and Request for Comments on Electricity Issues[48] in order to provide a forum for public discussion of major issues affecting the electric utility industry. The Commission identified five major issues: market based pricing; integrated resource planning; transmission access and pricing; mergers and acquisitions; and issues under the Clean Air Act (*e.g.*, emissions allowance trading).

The public conference was held on June 18, 1991. The Commission heard oral testimony from representatives selected across the entire spectrum of interests. The Commission allowed additional time for supplemental comments in its June 28 Notice of Additional Time. With that notice, Commission Trabandt asked a number of questions on a broad range of issues and included an extensive discussion of and suggested guidelines for a so-called "safe harbor" for expedited review of certain market pricing cases. Nearly one hundred parties filed comments or supplemental comments in the proceeding.

The Commission has not yet responded to the testimony or comments. However, a speech by Chairman Allday to the American Bar Association on August 13, 1991, four days after the Commission's Northeast Utilities merger decision, may provide considerable insight to the direction which the Commission plans to take.

The central theme of the Chairman's speech was that the FERC must take all steps necessary and within its authority to promote generation competition in the utility industry. In that regard, he advocated amending PUHCA. In order to achieve this policy objective Chairman Allday suggested a rulemaking setting forth certain filing guidelines for IPPs, so-called affiliated power producers (APPs), and traditional utilities. He identified the biggest issue as mitigation of market power in transmission. He suggested a "safe harbor" which would result in expedited review of certain transactions, and said that an open-access transmission tariff would presumptively mitigate market power and remove the potential for affiliate abuse.

IV. Other Issues

A. *Filing Procedures*

On August 5, 1991, the FERC issued a policy statement concerning the timing of electric rate filings. This statement followed its August 2 order in a *Central Maine Power Co.* (*Central Maine*) rate filing in which the Commission was sharply critical of the utility for having filed fourteen after-the-fact market-based agreements for services which had already been initiated and terminated.[49] Central Maine asserted that its failure to file those agreements earlier

48. 55 F.E.R.C. ¶ 61,069 (1991).
49. 56 F.E.R.C. ¶ 61,200 (1991).

was inadvertent and unintentional, but FERC approval was nonetheless appropriate because the rates were consensually determined in arm's-length transactions. Chastising Central Maine for its delay in filing, the FERC stated that timely filing of market-based rates was particularly important because "the Commission cannot cure a defective market or market process retroactively."[50]

The Commission's new policy requires: (1) all agreements embodying non-traditional (*i.e.*, other than cost-based) rates must be filed with the FERC at least sixty days before service is expected to commence; (2) henceforth, the Commission will consider waiving the sixty-day notice requirement for such non-traditional rates only in extreme circumstances; (3) all utilities currently providing services under existing but unfiled agreements embodying non-traditional rates must file those agreements within sixty days; (4) for those agreements filed within sixty days, the seller will be required to refund, with interest, all revenues collected thereunder in excess of one hundred percent contribution to fixed costs from the date service commenced to the date the FERC accepts the rate; (5) for those agreements filed after the sixty-day period, the seller must refund, with interest, all revenues collected thereunder in excess of variable O&M costs from the date the FERC accepts the rates.

All traditional cost-based rates must be filed at least sixty days before service is expected to commence; the FERC will waive that requirement only upon a showing of "good cause." Finally, those utilities wanting to take advantage of short-term sales and fast-breaking coordination opportunities should file a tariff with a rate cap of one-hundred percent contribution to fixed costs. This cap appears to preclude the opportunity to cap flexibly-priced rates which would recover revenues in excess of fully allocated costs.

On October 22, 1991, the FERC issued an order on rehearing[51] in which it clarified that the term "filing date" as used in the *Central Maine* policy statement means the date of the utility's initial submission, even if subsequently the subject of a staff deficiency letter. An intervenor had expressed concern that, since FERC staff often requests additional information after the initial filing, the sixty day advance notice period would not commence until the additional information is submitted to staff; that is, the filing date is deemed to be the date the additional information is submitted, rather than the date of the initial filing. Such a delayed commencement of the sixty-day notice period could inadvertently cause the utility to lose significant rate revenue. The FERC agreed that such a result was unintended.

> The Commission does not intend to penalize utilities for amending timely, good faith filings pursuant to Commission staff requests for additional information. Accordingly, the Commission hereby clarifies that, for purposes of the application of the policy statement, the timeliness of a utility's filing will be judged according to the date of the utility's initial submission of a proposed rate or change in rate. The Commission understands that staff's issuance of a deficiency letter postpones the actual "filing date" of the rate filing, from the date that data complete enough to accommodate staff review is filed. However, a good faith initial filing which inadvertently may be deficient will satisfy the requirements of

50. *Id.* at 61,818.
51. Central Maine Power Co., 57 F.E.R.C. ¶ 61,083 (1991).

the Policy Statement. Conversely, a filing which is a parent nullity will not.[52]

But less than a month later, in a case involving Duke Power Company,[53] the FERC held that rate filings are not complete and a filing date cannot be established until all required materials are submitted. Duke Power filed a two-phase rate increase with the FERC on September 19, 1991, and filed an amendment on October 2. The FERC stated that as a matter of policy the filing date will be the date of the filing of the amendment and not the date of the original filing. According to the Commission,

> With respect to the appropriate effective date, we note that Duke's original filing was tendered on September 19, 1991, but that an amendment was filed on October 2, 1991. We take this opportunity to remind utilities that filings are not complete and a filing date cannot be established under our regulations until all supporting materials that are required to be submitted are submitted, and the Commission here announces that, for all rate filings made after thirty days after publication of this order in the Federal Register, the Commission will consider *any* amendment or supplemental filing filed after a utility's initial filing—whether submitted *sua sponte* or not—to establish a new filing date for the filing in question.[54]

B. Generic Rate of Return on Common Equity

On January 2, 1992, the Commission issued its final rule abolishing its generic benchmark determination of rate of return on common equity for public utilities and rescinding its implementing regulations.[55]

On August 9, 1991, the Commission issued a Notice of Proposed Rulemaking[56] inviting comments on two issues relating to the generic benchmark (growth rate and flotation cost adjustment) and, more importantly, on whether the generic benchmark should be retained, abolished, or changed. The Commission had adopted its benchmark procedure in July 1984.[57] Although originally intended to provide guidance to parties in rate proceedings and to serve as a reference for the Commission in setting allowed rates of return . . . since that time, the benchmark rate has remained advisory, with the allowed rate of return for each individual utility determined on a case-by-case basis.

Noting that, after seven years of experience, it was able to evaluate the benefits of the benchmark procedure, the Commission concluded that the few benefits realized did not warrant retention.[58] The only benefit noted was the adoption of a more standardized methodology to determine the return on

52. *Id.* at 61,305 (footnote omitted).

53. Duke Power Co., 57 F.E.R.C. ¶ 61,215 (1991).

54. *Id.* at 61,713 (emphasis in original) (footnote omitted).

55. Generic Determination of Rate of Return on Common Equity for Pub. Util., 58 F.E.R.C. ¶ 61,013 (1992), Order No. 538, No. RM91-17-000 (January 2, 1992).

56. Generic Determination of Rate of Return on Common Equity for Pub. Util., 56 F.E.R.C. ¶ 61,276 (1991); 56 Fed. Reg. 41,098 (1991).

57. Order No. 389, 49 Fed. Reg. 29,946, [Regs. Preambles 1982-1985] F.E.R.C. Stats. & Regs. ¶ 30,582, *reh'g denied*, Order No. 389-A, 49 Fed. Reg. 46,351 (1984).

58. 57 Fed. Reg. 802 at 803 (1992). The Commission received 33 comments, most on the ultimate question of whether the generic benchmark is useful and should be retained, and generally split on that question.

equity in rate cases, which the Commission said it intended to continue using in any event. Benefits that failed to materialize include: resources were not saved, contentiousness was not reduced, rate case uncertainty was not reduced, and the benchmark proceedings did not result in a better understanding of industry trends. Finally, the Commission stated that the benchmark does not provide any particular consumer protection.

C. *Price Squeeze*

In *Cities of Anaheim, Riverside v. FERC*,[59] the court reversed two FERC decisions finding that Southern California Edison Co. (Edison) had engaged in an unlawful regulatory price squeeze in connection with wholesale rate filings for certain municipal utility customers of Edison. The decision, however, is of little precedential value. In the second of the two FERC decisions the Commission had announced that it would abandon its long-standing presumption that a disparity in wholesale and retail rates resulted in potential anticompetitive effects. The Commission had declined to apply the new rule in the Edison case because the parties had tried the matter under the prior policy. The court found that Edison had presented sufficient evidence to overcome the presumption of anticompetitive effect. The court also affirmed the Commission decision on price discrimination issues.

D. *Contract Interpretation*

In *Cajun Electric Power Coop. v. FERC* (*Cajun*)[60] the court remanded to the FERC its summary resolution of a contract interpretation dispute. Cajun had filed a complaint seeking a FERC order to enforce a contract between it and Gulf States Utilities Company. The Commission summarily ruled the contract unambiguously supported Gulf States' position, denied Cajun's request for an evidentiary hearing and granted summary disposition for Gulf States. The court held that the contract was ambiguous and therefore remanded for further proceedings.

The dispute centered on Cajun's rights to use the Gulf States distribution system and to build and interconnect facilities to the Gulf States system. In the court's view, two relevant provisions in the contract seemed to be inconsistent, nevertheless the FERC had rejected the complaint, resolving the apparent conflict in a way which the court regarded as "rather strained." Cajun was denied the right to present evidence concerning the parties' intent as to the resolution of the inconsistency.

The court acknowledged the general rule requiring judicial deference to an agency's interpretation of a jurisdictional settlement agreement, and that the agency's interpretation is entitled to the benefit of the doubt. But that rule was inapplicable here. "Benefit of the doubt, however, implies as a precondition a legitimate doubt, or, in legal terms, an ambiguity."[61] Deference is appropriate only when an ambiguity exists, and the deference is accorded to

59. 941 F.2d 1234 (D.C. Cir. 1991).
60. 924 F.2d 1132 (D.C. Cir. 1991).
61. *Id.* at 1136.

the agency's resolution of the ambiguity. Deference is not required on the threshold question of whether contract language is or is not ambiguous. The court held it must remand since the FERC had erroneously concluded that ambiguous language was clear, and could be resolved summarily against Cajun. "The Commission's cursory treatment of Cajun's claim simply will not do. The grant of "summary judgment" based on the notion that this contract unambiguously favors Gulf States seems at least high-handed and perhaps driven by regulatory policy considerations not apparent on this record."[62]

E. Legislative Developments (PUHCA Amendments)

Although not literally pertaining to the regulation of electric utilities under the FPA, federal legislative proposals to amend the PUHCA[63] have generated so much interest—indeed controversy—that they warrant discussion here.

The PUHCA regulates the corporate form of, and a wide range of transactions by, electric utility holding companies. The PUHCA defines as a holding company as an entity which owns more than ten percent of the voting control, or otherwise actually controls, a company which owns or operates electric generation, transmission, or distribution facilities. The statute requires that, except when one of a limited number of narrowly-drafted exemptions is available, the holding company is subject to rigorous regulation by the Securities and Exchange Commission of the geographical and substantive scope of its business, its corporate structure, its affiliate transactions, and its financings. Such regulation is generally considered to be unacceptable by developers and potential owners of IPPs. Under current law, IPP developers must limit their projects of QFs, ownership of which is exempt from the PUHCA, or adopt inefficient structures or project configurations in order to qualify for a PUHCA exemption.

On February 20, 1991, the Bush administration proposed its National Energy Strategy (NES). Among its many provisions, the NES proposed that the PUHCA be amended to allow businesses to build, own, and operate powerplants using virtually any fuel source or generation technology in more than one geographical area. State regulatory authorities would be free to determine whether and to what extent new generation would be developed by utilities or procured competitively from sources including independent power producers.

Various bills were introduced in Congress early in 1991 proposing amendments to the PUHCA. Two bills, S. 1220[64] and H.R. 776,[65] both of which proposed comprehensive energy packages, emerged as the principal PUHCA legislation of the year. Both bills incorporated proposals concerning a number of controversial issues in addition to the PUHCA.

The proposed legislation that became S. 1220 was introduced by Senators

62. *Id.* at 1135.
63. 15 U.S.C.A. § 79 *et seq.* (1981).
64. S. 1220, 102d Cong., 1st Sess. (1991).
65. H.R. 776, 102d Cong., 1st Sess. (1991).

Johnston (D-La) and Wallop (R-Wy) in February 1991. The Energy and Natural Resources Committee reported the bill by a vote of 17-3 in May. The bill would create a new class of IPP called "exempt wholesale generators" (EWGs) by permitting EWGs to own and operate generation facilities dedicated to wholesale sales to electric utilities without treating their owners as holding companies under the PUHCA. EWG status would be denied to existing facilities in a utility's ratebase unless approved by the utility's state regulatory commission. State commissions would be given access to the books and records of EWGs to foster their ability to police potential self-dealing and cross-subsidies between a utility and its EWG affiliates. The bill would confirm the authority of state commissions to review the prudence of power purchase decisions by utilities subject to their jurisdiction, although purchases from EWGs would be reviewed in advance. The FERC would be given authority to prevent an EWG from gaining undue advantage from any relationship it might have with a utility. Opponents of S. 1220, concerned with other controversial provisions, defeated on November 1 a motion to close floor debate, and the bill was then removed from the Senate calendar for the rest of the session.

H.R. 776 was sent by the House Energy and Power Subcommittee to the Energy and Commerce Committee in October 1991 where it is still pending mark-up. H.R. 776 would exempt PPs from the PUHCA, subject to FERC authority to review IPP power sales agreements to protect consumers from cross-subsidization and discrimination. It would also prohibit sales of power from an IPP to an affiliated utility and confirm state regulatory authority to review the prudence of utility purchases from IPPs. As discussed in subsection II.E., H.R. 776 also includes provisions amending the FPA to expand FERC's authority to order transmission access.

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