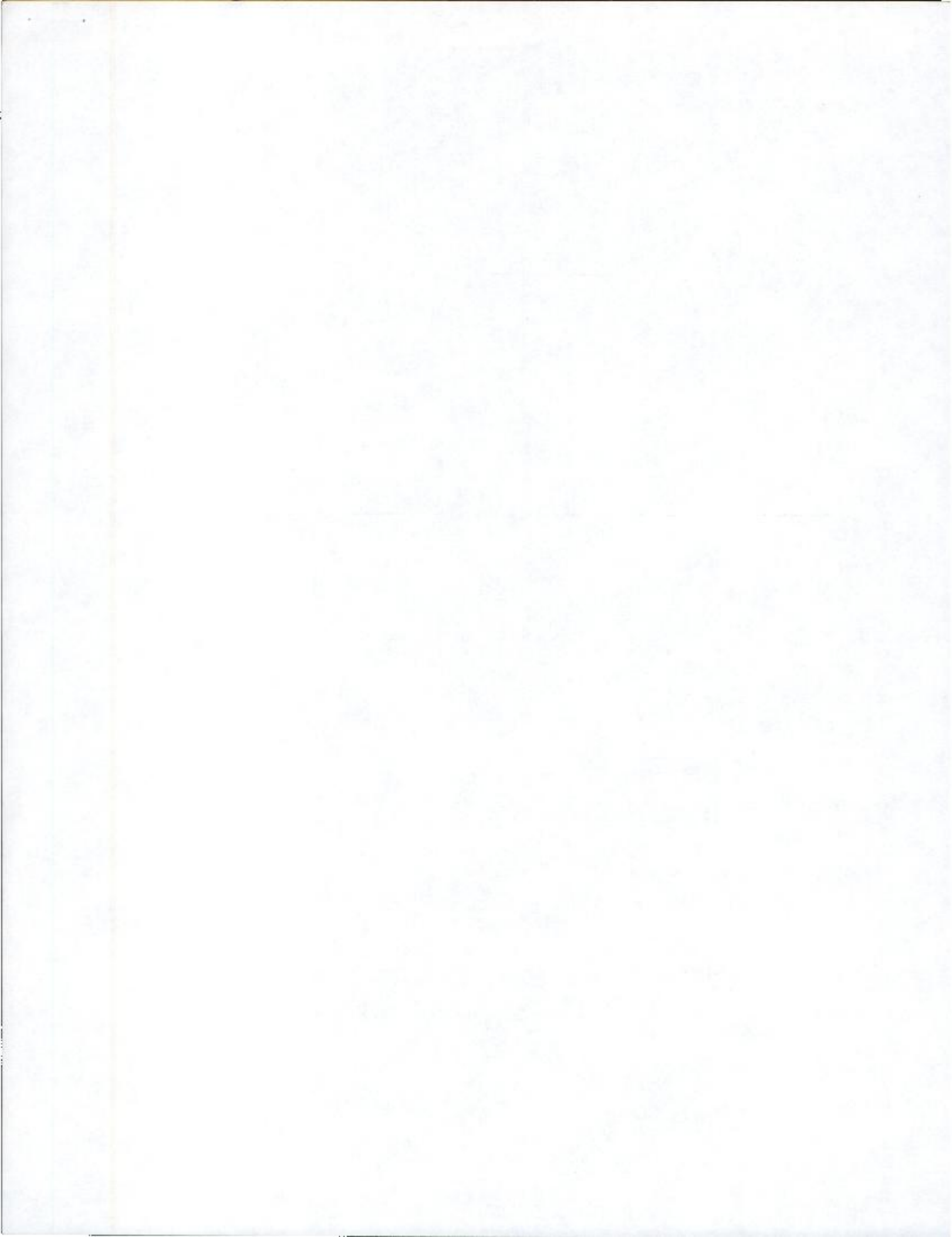


Implementing the Energy Policy Act: A Regulatory Analysis One Year Later

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INTRODUCTION

It has been a year since Congress substantially altered the basic legal structure underpinning the electric utility industry with the Energy Policy Act (EPA) of 1992. This law represented the most significant modification to the legal structure of the electric utility industry since the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978.

The EPA introduced the concept of "exempt wholesale generators" (EWGs) under section 32 of the Public Utility Holding Company Act (PUHCA). Any entity can now own EWGs without having to be regulated under PUHCA. EWGs can be located in the U.S. or abroad. In PUHCA section 33, Congress authorized utilities and holding companies to invest in foreign utility companies (FUCOs).

The new law also modified the Federal Power Act (FPA) by amending section 211 to give FERC greater authority to order utilities to provide transmission access. It amended section 212 to specify appropriate pricing for transmission service under section 211. New section 213 requires utilities to respond to good faith transmission requests within 60 days and requires FERC to gather information from utilities about transmission availability and constraints.

Finally, the EPA added four new standards for state commissions to consider under PURPA. Under these standards, utilities "shall employ integrated resource planning" with an opportunity for public participation in the process. States are to consider whether utilities should be able to profit from investments in conservation and demand side measures to the same extent they profit from building new plants. Further, states must consider whether rates for an electric utility will encourage investment to improve efficiency in generation, transmission, and distribution. Finally, state commissions are required to consider the impact of utility purchases from highly leveraged EWGs on the utility's cost of capital, system reliability, and a utility's competitive situation vis-a-vis EWGs. They are also to consider whether to implement procedures for advance approval of a utility's purchases or to require a reasonable assurance of long-term fuel supply adequacy before approving a wholesale purchase.

These legislative changes offer a broad outline of changes in the industry structure and regulation, leaving numerous important questions for the regulatory agencies who must implement the EPA. The result of its implementation may be a long time in the making.

The agency with the greatest role in implementing the EPA is FERC, which must approve all EWG applications and administer the new transmission access provisions of the FPA. Despite FERC's role in the EWG determinations, the SEC retained its functions as lead agency under PUHCA. In this role, it must approve the issuance of securities by registered holding companies for financing the acquisition of EWGs and FUCOs. These agencies have already begun the task of implementation.

Congress also gave states an important role. States have a direct say in the establishment of certain types of EWGs and in investment in foreign utility companies by exempt holding companies. States must also approve any transactions between a utility and its affiliated EWGs and oversee the new PURPA standards.

This paper will discuss the actions to date of these agencies in implementing the EAct. It will focus both on the actions resulting directly from the Act and on some of the related issues spawned by the Act.

EXEMPT WHOLESALE GENERATORS AND FOREIGN UTILITY COMPANIES

The EAct specifies that an exempt wholesale generator must be exclusively in the business of selling power at wholesale. Any utility, utility holding company, or other entity can own an EWG without having to be regulated as a utility holding company under PUHCA. While easy to obtain, EWG status is not completely automatic. After an applicant files for EWG status, FERC has 60 days to approve or deny the request; FERC's failure to act in time will mean that the application is granted. The Congressional history of the EAct indicated that FERC's oversight is intended to be purely "ministerial," meaning that the Commission's role is limited to ensuring that EWGs meet the specifications of the statute.

Commonwealth Atlantic, an IPP selling power to Virginia Power, filed the first EWG application a day after the EAct became law, and FERC has since received over fifty more. As of June 1, 1993, FERC had granted EWG status to 47 applicants. Nine applications have been denied, six of which have refiled.

FERC's EWG Rule

The EAct required FERC to establish generic rules on processing EWG applications. The Commission initiated the process on November 10, 1993, with a Notice of Proposed Rulemaking. After receiving comments from fifty parties, the Commission issued Rule 550 on February 10, 1993. Under Rule 550, applicants for EWG determination must file: (1) a sworn statement of fact attesting to the eligibility for EWG status, (2) a brief description of the facility or facilities involved, and (3) any necessary state commission orders. A copy of the EWG application must also be filed with the SEC and any affected state commission.

Notice of EWG applications will be published in the Federal Register and will permit comments or interventions. However, Rule 550 limits the comments to the adequacy or accuracy of the facts presented; FERC indicated that comments or interventions will not be allowed to delay determinations. The Commission will only consider comments pertaining to the factual representations relevant to the statutory definition of an EWG. It will deny intervention to parties that raise other issues irrelevant to such determination. FERC will not entertain requests for rehearing.

Notices of EWG determinations will be sent to applicants, the SEC, and interveners. FERC will not issue any deficiency letters or allow any amendments to pending applications; applicants that are denied may refile with additional information or explanation. A filing fee of \$1,000 will be applicable to those applicants who will not become public utilities. EWG's that do become public utilities will be assessed annual charges under Part 382 of the Commission's existing rules.

FERC also required EWGs to inform it of any material change in facts that may jeopardize eligibility for EWG status. Within 60 days of such notice, the EWG may apply for new determination as an EWG; file a written explanation of why the material change does not affect the EWG's status; or notify FERC that it is no longer seeks to maintain EWG status. The rule also requires applicants to disclose information regarding affiliation with an electric utility.

On rehearing, FERC made two substantive determinations in response to issues that had arisen in individual EWG cases interpreting the statutory requirement that EWGs own or operate *and* sell power at wholesale. Order 550-A, issued April 14, 1993, addressed the situation where one firm is the owner of an eligible facility but another is its operator. In *KFM Pepperell*, FERC had granted EWG status to a facility's owner but denied EWG status to its operator, on the ground that only the owner of the facility was actually selling the power at wholesale (62 FERC 61,182, March 1, 1993). FERC said that it will deem that an operator is selling electricity at wholesale if the operator is the agent of the owner/seller. In other words, if the operator of an eligible facility carries out its responsibilities subject to the direction of the person who sells power from the eligible facility, FERC will consider the operator to be a seller, and thus, an EWG.

FERC made a similar change where an eligible facility is leased to another company. In *InterAmerican Energy Leasing Co.*, FERC had denied the application of an owner of an eligible facility because the facility was to be leased to another party on the grounds that the lessee, not the owner, would actually be selling the power (62 FERC 61,283, March 26, 1993). In Order 550-A, FERC said that where an owner of eligible facilities leases those facilities, it will treat the lease of the facility as a sale of electric energy at wholesale, enabling both the lessor and lessee to qualify as an EWG.

Other EWG Cases

Before it could issue generic rules on EWGs, FERC had to act on several EWG applications. This analysis will focus on the cases that established important precedent. In *Richmond Power Enterprises, Entergy Richmond Power Corp., and Entergy Power Development Corp.* (62 FERC 61,157, February 18, 1993) the Commission answered the question of whether the EAct requirement that EWGs be exclusively engaged in the wholesale power business precludes an EWG from also selling by-products, such as steam or fly-ash. Relying on remarks of Senator Bennett Johnston in the legislative history, FERC held that an EWG may sell steam or other by-products of generation. FERC also held that an EWG may also own a QF, citing new section 32(j) of the PUHCA as authority. FERC found nothing in the EAct or its legislative history to indicate that a

facility satisfying the requirements for QF status may not also be an EWG, as long as it meets the statutory definition of an EWG.

In *Louis Dreyfus Electric Power, Inc* (62 FERC 61,254, (1993)), FERC denied EWG status to a bulk power marketer that would assume contractual title to power and then resell that power. LDEP sought EWG status to avoid PUHCA regulation by the SEC until the SEC determines that LDEP does not own facilities used for generation of electric energy. FERC said that the SEC has never determined whether the electric facilities includes "books, records, power sales contracts, or other paper" for purposes of PUHCA. FERC denied the application because the term "eligible facility," as used in the EPAct, does not include contracts for the purchase and sale of power. FERC held that eligible facilities had to be physical facilities. In addition, FERC held that an EWG must generate at least some of the energy it plans to sell.

Although the EPAct established a clear legal framework for independent generation, FERC had already considered nontraditional pricing of competitive sales from utility and non-utility sellers of bulk power. In the past five years, the Commission has established policies for allowing market-based rates for entities that lack or mitigate their market power. In doing so, it established a test for determining an entity's market power, which, according to FERC, depends on the supplier's dominance in generation and transmission and its ability to erect other barriers to entry. The Commission has also grappled with the question of affiliate transactions at market-based rates, allowing them if they conform to a market-based benchmark and are not the result of undue preferential dealing. In each of these areas, the Commission established precedent on a case-by-case basis. (See EEL paper, FERC Policy Directions On Transmission Access and Market Based Rates for a discussion of FERC's market-pricing precedent.)

SEC Rules

Although the EPAct expressly allows registered holding companies to invest in EWGs, the Securities and Exchange Commission still must approve all issuances of securities. Congress gave the SEC six months to issue regulations involving EWGs, after which the SEC cannot approve a registered holding company's issuance of securities to finance an EWG until rules are in place. Congress did not specify a time when regulations involving foreign utility companies (FUCOs) needed to be issued.

On September 23, the SEC issued final rules regarding the issuance of securities by registered holding companies for the financing of EWGs and FUCOs (Release No. 35-25885, File No. S7-9-93). The rule would establish a safe harbor providing certainty that a registered holding company would obtain SEC approval to issue securities if it met certain conditions. Under the safe harbor, a registered holding company would be able to invest up to 50 percent of its retained earnings in EWGs and FUCOs. Further, it would have to provide access to all books and records of EWGs and foreign utilities, which must be kept in accordance with GAAP and FERC uniform system accounting standards. Only 2 percent of the registered holding company's utility personnel could provide services to affiliated EWGs and FUCOs. In addition, once a registered holding company

has reported losses that cause a 10 percent decrease in its consolidated retained earnings, the safe harbor will be unavailable if aggregate investment in EWGs and FUCOs exceed 2 percent of total capital invested in system utility operations.

The SEC has proposed applying similar safe harbor criteria to the actual acquisition of FUCOs by registered holding companies. However, several interveners were highly critical of the proposal, particular Congressman Edward Markey (D-MA), Chairman of the House Subcommittee on Telecommunications and Finance. Pointing to the comments filed by NARUC, the National Association of State Consumer Advocates, APPA, Environmental Action, and Consumer Federation of America, Congressman Markey challenged the safe harbor approach as apparently being "inconsistent with the statutory language and Congressional intent" of the EPAct. He interpreted the statutory language to require the SEC to "ensure that certain transactions between exempt wholesale generators ... and registered holding companies have 'no adverse impact' on any utility subsidiary or its customers ..." Congressman Markey suggested that some "factual analysis of particular situations, particularly in the foreign area, where we know very little, is necessary for consumer protection" and suggested that a complaint process would be needed. He requested that the Commission withdraw the proposal and reissue a new one consistent with the EPAct.

In response to these concerns the SEC deferred action on rules pertaining to FUCOs, pertaining to registered holding company investment in FUCOs, noting that the Commission wished to consider further the comments it received on its proposals. The Commission also issued a NOPR amending Rule 87, concerning certain intrasystem agreements between affiliated companies of a registered holding company. The amendment to Rule 87 would clarify that Commission approval, by order, is required for intrasystem service sales and construction agreements involving EWGs and FUCOs and another subsidiary in the registered holding company system. The proposed amendment is intended to insure that necessary personnel and other resources are not improperly shifted from the system's core utility business to EWG or foreign utility company activities. Comments on the proposed rule are due to the SEC on November 30, 1993.

State Commission Activities

The EPAct also gave states an important role in various aspects of implementation. State public utility commission (PUCs) must approve the conversion of a plant in a retail rate-base to an EWG on the showing that the conversion will benefit customers, is in the public interest, and does not violate state laws. State PUCs must also approve all sales from an EWG to an affiliated utility over which the PUCs have jurisdiction. In approving such sales, PUCs must find that they have sufficient legal authority, resources, and access to the books and records of the utility and its affiliate. Further, PUCs must determine that an affiliate transaction will benefit customers, does not violate state law, does not give the affiliated EWG an unfair competitive advantage, and is in the public interest. Over 40 states have initiated proceedings on standards.

Similarly, state PUCs with jurisdiction over an exempt utility holding company affiliated with a FUCO must certify to the SEC that they have authority and resources to protect utility ratepayers and that they intend to exercise this authority. No state has acted on this provision yet.

Under the new PURPA standards, states are also required to examine the effect of EWG leveraging on the purchasing utility's cost of capital and system reliability. PUCs must also consider whether to adopt standards concerning adequacy of the EWG's fuel contracts. Eight states have initiated procedures on these PURPA standards.

TRANSMISSION ACCESS

As with independent generation and market-based rates for bulk power, FERC had also promoted greater transmission access well before the passage of the Energy Policy Act. Since 1988, the Commission has frequently required transmission access as a condition for approving utility mergers and allowing utilities and their affiliates market-based rates for bulk-power transactions. The EAct clearly strengthens FERC's authority to mandate access. The transmission provisions of the EAct probably raise the most significant questions on implementation.

Section 211 Transmission Cases

The first petition for transmission access under the EAct filed with FERC raised a basic question of what constitutes transmission service. The case involved a contract dispute between Tex-La Electric Cooperative and Texas Utilities Company (TU). The actual provision of transmission was not at issue; the utility was already providing transmission service. The coop sought FERC mandated scheduling service, which TU said it did not have to provide under terms of its contract with Tex-La.

FERC agreed with TU and denied Tex-La's request (64 FERC 61,162 (1993)). It found that Tex-La was not requesting transmission service; rather, it was seeking a firm capacity credit for generation supplied to Texas Utilities. The Commission rejected Tex-La's attempt to cloak this within the "transmission services" umbrella. Although it denied this first request for transmission service, FERC made it very clear that it fully intends to carry out its Congressional mandate to "assist the development of a competitive electric wholesale generation market by encouraging and, where necessary and appropriate, mandating transmission access on reasonable rates terms and conditions."

The second request for transmission service involves five partial requirements customers of Appalachian Power Company (APC), a subsidiary of American Electric Power Company (TX93-2). Four of the applicants are municipal utilities in Virginia and are members of the fifth applicant, Blue Ridge Power Agency, a nonstock membership corporation which supports power supply acquisition activities of its members. The applicants allege that AEP has refused to provide transmission services in connection with Blue Ridge's planned purchase of term capacity and energy from PSI Energy.

Like *Tex-La*, this case also involves a contractual dispute. Blue Ridge, which has entered an agreement to purchase power from PSI, claims that its contract with APC permits it to reduce its capacity purchases from APC by 15 percent with a one-year notice. APC says that capacity can only be reduced for reasons that do not include purchases from alternative suppliers, unless power is available from SEPA, the government-owned Southeast Power Authority, which the contract specifically allows.

A sharply divided Commission voted on September 30 to establish a limited, expedited hearing on the case (64 FERC 61,331). Concluding that the contract was, in fact, ambiguous, a bare majority agreed that a hearing was necessary to determine the meaning and intent of the contract. Commissioners Hoecker and Santa dissented, arguing that the agreements, although complicated, were clear: Blue Ridge could only purchase power from APC, except for purchases from SEPA. They argued that, by not denying to hear the case outright, FERC was opening the door for any requirements customer to get out of unfavorable bulk power contracts that, through their complications, could conceivably be ambiguous.

In the third transmission service request, Wisconsin Electric Power Company (WEPCO) requested that FERC order Upper Peninsula Power Company (UPPCO) to wheel WEPCO power to an isolated part of WEPCO's territory at Greenstone (TX93-3). WEPCO currently serves Greenstone via UPPCO's resale service schedule. Because it purchases a major share of its capacity and energy from WEPCO, UPPCO argues that WEPCO generation is already serving the Greenstone area and the requested service would have no net effect on operation of WEPCO's or UPPCO's generators. Since rates for Greenstone customers are the same as those of customers served directly off the WEPCO system, UPPCO says, rates paid by retail ratepayers in the Greenstone area would be expected to remain unchanged.

WEPCO maintains that the Energy Policy Act did not anticipate the preservation of pre-existing competitive relationships. WEPCO further argues that FERC has contended that its job is to "protect competition, not particular competitors." Further, WEPCO insists that it has no legal or operational requirement to offer a reduction in capacity purchases and claims that "the loss of two megawatts of sales is within UPPCO's normal business risk and should not be a reason to deny the requested transaction." WEPCO recently withdrew its request in favor of voluntary negotiations.

The fourth and latest application to FERC for a Section 211 order requiring transmission access asks that Florida Power & Light (FP&L) be required to provide "network" access to the Florida Municipal Power Agency (FMPA). This is the first petition to seek such "network" access and the first to be combined with a Section 206 complaint, against FP&L's current transmission rates. The dispute stems from the NRC licensing proceedings for an FP&L nuclear unit. FP&L agreed to licensing conditions assuming transmission service to several Florida municipal utilities, FMPA among them. FMPA claims that the provisions entitle it to network access, and is currently suing FP&L in federal district court.

In March 1993 FP&L filed with FERC a comprehensive restructuring of its transmission, wholesale power, and interchange provisions. The transmission tariffs contain open access provisions; however, the character of the access offered is unsatisfactory to FMPA.

FMPA's petition asserts that FP&L's transmission rates are unjust and unreasonable under Section 206 of the Federal Power Act, contending that the NRC's antitrust conditions entitle it to transmission over FP&L's network without having to pay multiple transmission charges. FP&L, FMPA complains, "seeks to impose multiples of its basic transmission charge as a function of the number of delivery points involved and a function of the maximum possible delivery to and from each point." This results, FMPA continues, in its "not hav[ing] the same transmission access that" FP&L has, and in its being "assigned a disproportionate share of transmission system costs."

Information Requirements Rule

On September 30, FERC issued its final Information Reporting Requirements Rule. The rule became effective on October 8, when it was published in the *Federal Register*. The final rule implements section 213(b) of the FPA, as amended by EPAct, which directed FERC to gather information necessary to inform potential transmission customers, state regulatory authorities, and the public of potentially available transmission capacity and known constraints.

The rule creates a new reporting form: FERC Form No. 715, Annual Transmission Planning and Evaluation Report. Transmitting utilities that operate grid facilities at or above 100 kV must file the form annually, beginning April 1, 1994. The Commission indicated that "it will not treat Form 715 information as confidential or limit public access to it," although in response to national security concerns raised by NERC and others, the Commission did not implement a proposal to require utilities to file a list of "critical" facilities. The Commission noted that the data provided by utilities under this rule would provide potential users with a screening tool, which will promote informed requests for transmission service and negotiations.

The final rule requires transmitting utilities either to authorize their regional or subregional organization to submit, in electronic form, regional or subregional power flow base cases, or to submit their corporate base case power flows to the Commission. Utilities must submit transmission system maps (regional, subregional and corporate) as well as a detailed description of transmission planning reliability criteria for the time frames and planning horizons used in regional and corporate planning. They must also submit a detailed description of transmission planning assessment practices and a detailed evaluation of anticipated system performance as measured against reliability criteria.

The final rule also amends existing Form No. 714, Annual Electric Control and Planning Area Report. The rule eliminates certain schedules that FERC no longer needs or which will be collected under new Form 715, and changes the filing date from May 1 to June 1. The rule also modifies an existing reporting requirement to require utilities to

submit hourly control area system lambda and planning area hourly demand data, which was previously submitted on a monthly and weekly basis, respectively.

Regional Transmission Groups

On June 30, 1993, FERC issued a Policy Statement encouraging the development of regional transmission groups (RTGs) and specifying what RTG agreements should contain. FERC's action stemmed from a compromise reached among a large group of industry players as Congress was on the verge of passing the EPAct. The compromise would have allowed a group of entities within a certain region to form voluntarily an RTG and develop their own access and dispute resolution schemes. This would have qualified them for limited exemption from FERC ordered transmission. The compromise was reached too late to be included in the bill. However, FERC, on its own initiative, sought comment on whether it has the authority to implement the compromise on its own authority and, if so, whether it should do so and the Policy Statement resulted (FERC Stat. & Reg. 30,976 (1993)).

While acknowledging that it does not have the authority to approve an RTG *per se*, FERC said that any RTG agreement involving contracts, rates, terms, and conditions of transmission in interstate commerce would fall under its regulatory purview and would have to be approved under Section 205 of the FPA. Although it always has to ensure that the results of RTG procedures are just and reasonable and not unduly discriminatory or preferential, the Commission said that it would give deference to those procedures that meet minimum standards.

FERC stated that a primary of an RTG is to facilitate the provision of transmission services to potential users and to resolve voluntarily disputes over the provision of such services. RTGs could "address disputes over transmission issues in a manner that satisfies the statutory standards of the FPA, and can minimize the number of applications seeking Commission orders for mandatory transmission services under section 211. Further, RTGs will encourage the resolution of technical issues by technical experts, as brought together by the RTG. This should be more efficient than the polarizing atmosphere of regulatory proceedings, said FERC.

For RTG agreements to gain Commission deference, FERC described seven components that should be contained in such agreements, although it indicated that it will allow a considerable degree of flexibility to reflect geographic, operational, historical, or other differences among regions. RTG agreements could also differ in level of detail and substance of terms, conditions, and rates.

FERC said that membership should be broad, allowing, at a minimum, any entity subject to or eligible to apply for a section 211 wheeling order. The geographic area should be large and contiguous enough to enable the provision of reliable, efficient and competitive transmission services. Foreign utilities interconnected with utilities in the U.S. should also be allowed to join. RTG agreements should also provide for consultation and coordination with relevant state regulatory, siting, and other authorities. FERC said that

state consultation is critical because of the states' role in setting retail rates that recover transmission costs, IRP, and siting of transmission lines. State involvement in RTGs will improve their communication with utilities and with each other to resolve issues among the states and utilities.

Member transmitting utilities of RTGs will need to make an affirmative commitment to provide transmission services for other RTG members, including the obligation to build new lines. They should also develop coordinated transmission planning on a regional basis and the sharing of planning information "with the goal of efficient use, expansion, and coordination of the interconnected electric system on a grid-wide basis." RTGs should have a provision recognizing the ability of parties to leave the RTG and specifying the responsibility of exiting parties.

RTGs should also include fair and non-discriminatory governance and decisionmaking procedures, said FERC. Particular attention must be made to protect the rights of entities that are more susceptible to the exercise of market power, such as transmission dependent utilities. RTGs need to include a voluntary dispute resolution procedure, and the Commission encouraged RTGs "to develop high quality alternative dispute resolution procedures for resolving technical and reliability issues." Although the FPA requires it to ensure that the results are just and reasonable and not unduly discriminatory or preferential, the Commission held that it has the authority to give deference to outcomes produced within an RTG, and it said that will do so.

Several groups are reportedly meeting to consider forming RTGs; two have released official announcements. Members of NEPOOL had reached an agreement on strengthening the pool to result in a formal regional transmission arrangement, as FERC had suggested in its orders approving the Northeast Utilities/Public Service New Hampshire (NU/PSNH) merger. The NEPOOL RTA would have allowed any purchasing entity to obtain transmission services, with rates based on revenue requirements and, in an effort to discourage transactions at particularly congested parts of the grid, the points of delivery. However, some parties are reconsidering the NEPOOL RTA because of more recent developments at FERC. Also, utilities in the desert southwest have formally announced their intention of forming a RTG. The Southwest Regional Transmission Association (SWRTA) would include utilities from Arizona, New Mexico, western Texas, southern Nevada, and southern Utah.

The RTG concept was discussed in a FERC order accepting the organizational documents filed by the Interregional Transmission Coordination Forum (ITCF). ITCF is a voluntary regional transmission association formed in 1991 to provide a forum to promote cooperation and coordination between owners, operators, and users of interconnected transmission systems in the hope of assuring system integrity and maximum use. It hopes to encourage investment in additional facilities to maintain reliability and enhance transfer capability. Its members include a diverse group of investor owned utilities, publicly owned utilities, cooperatives, and non-utility generators. It also provides a forum for non-binding dispute resolution. With over forty members from the Midwest, South, Mid-atlantic States, and New England, ITCF encompasses a large swathe of the Eastern Interconnection.

Although ITCF did not request recognition as an RTG, FERC found that "the ITCF does not contain most of the elements of an RTG as defined" by its recent Policy Statement (ER92-667, September 3, 1993). Missing, said FERC, was any mention of how ITCF will coordinate its actions with state regulatory authorities as well as an obligation by ITCF members to provide transmission services. Further, while ITCF does have a Planning Committee, FERC could not conclude that it will result in a coordinated plan to meet the reliability and economic demands on the transmission system. Finally, FERC noted that ITCF had no termination provisions and said that its governance provisions might not meet the standards of its Policy Statement.

Given that ITCF is not a full-fledged RTG, FERC said that it will continue to review all contracts that result from ITCF procedures under the traditional section 205 just and reasonable standard. It will not offer deference to ITCF decisions as it would to those reached by RTGs. This fact caused Commissioner Hoecker to dissent. He advocated rejection of the filing, arguing that the agreement is not likely to be of any practical or jurisdictional consequence. He further doubted that the Commission's acceptance of the filing will lead to constructive coordination agreements. He was concerned that FERC's acceptance of the filings may "inhibit or arrest progress toward formation of an RTG."

Policy Statement on Good Faith Requests for Transmission Service

The EAct specifies that the process for an entity seeking transmission access must begin with that entity making a "good faith" request with the transmitting utility. The utility then has 60 days to respond to the transmission request. The Act did not define what constitutes a good faith request or response.

To clarify this ambiguity, FERC issued a Policy Statement on July 14, 1993 (PL93-3). Emphasizing that these guidelines are "neither rigid nor all-encompassing," FERC said that a good faith request must include the identity of the purchaser, assurances that the prospective purchaser of the transmission services is eligible to request the services, and assurances that the Commission is authorized to order the type of services requested under appropriate circumstances. Good faith requests also need to specify the type of services requested. FERC interprets the EAct and its legislative history as not limiting the definition of the "transmission services" the Commission may order under section 211. FERC will permit any party to request "network" service under section 211. While FERC believes that service more flexible than point-to-point can be ordered under Section 211, and thus is a proper subject for good faith requests, FERC requests comments on the limitations, if any, on the Commission's authority to order such service. The party requesting transmission services should specify the character and nature of the services, ranging along a continuum from point-to-point to network. The Commission requests comments on whether requiring the specification of point(s) of receipt and delivery will unduly restrict the ability of parties to request the flexibility of the transmission service some parties need. (A FERC ALJ has ruled on Consumer Power's transmission tariff incorporating a network service proposal. See Below.)

Good faith requests will also need to identify other parties expected to be delivering and/or receiving power from the transmitting utility. To the extent known, the requesting party must indicate utilities that will be affected by the transaction, either through the contract path or the actual power flows. They must also include the proposed dates for initiating and terminating the requested transmission services, the total amount of transmission capacity being requested, and the expected transaction profile. To the extent known, the requesting party should provide enough information to permit the transmitting utility to model the power flow impact on its system of both receipts and deliveries (hourly load factor data).

Finally, good faith requests will have to specify the degree of firmness of the requested service, and, to allow the transmitting utility to group multiple requests in response to a bid for generation resources, transmission requestors will have to identify if the request is made in response to supply solicitations. Good faith requests will also have to specify terms and conditions requested. FERC does not think that it is necessary that a requestor propose rates, terms and conditions for services it is requesting, as provided under Section 213(a). The party can instead specify a preferred rate methodology, or an existing tariff, contract or rate. The transmitting utility is not bound by this request and may reject the proposed rates, terms and conditions and propose its own.

The Commission also specified what must be in a good faith reply from the transmitting utility. Within 10 days of receiving a request, the transmitting utility should acknowledge the request. The 60-day period begins to run upon receipt of the request. The transmitting utility may request clarification of information needed to evaluate the specific services being requested. If the requesting party believes that this is a delaying tactic, it may raise the issue in a 211 proceeding after the 60-day period expires. The transmitting utility receiving the request must notify the requesting party of the cost-based fees associated with the evaluation of a transmission request, and should specify the date by which it will respond to the request or initiate negotiations on a mutually acceptable date other than that set by the 60-day clock;

If it believes it can provide the requested service from existing capacity, the transmitting utility should offer a proposed service agreement covering the services it will provide, including detailed pricing specifications for each component of service. A regulatory "cost-of-service" study is not necessary. The agreement should include all applicable terms and conditions. A clear statement of time the offer will remain open should also be included. The purchaser may ask for a reservation or contingency arrangement. At a minimum, the transmitting utility should permit the requestor sufficient time to review agreements and coordinate multiple stages of joint transactions.

If it determines that it must construct additional facilities or modify existing facilities in order to provide all or part of the requested services, the transmitting utility must provide a description of why and for how long its grid will be constrained. The utility should also offer the requestor an executable contract for a study to determine how the constraint can be relieved which specifies the cost and production time for the study. The

study should result in the determination of how the transmitting utility will remove the constraint, how long it will take and how much it will cost. If a utility can provide part of the service, it should offer to do so and may be able to treat the request as two separate transactions involving existing and expansion of facilities.

The Policy Statement is final and is effective on the date published, although comments on certain aspects of the statement have been requested and are due by September 20.

Other Transmission Actions at FERC

In the first official action involving "network transmission service (NTS)," a FERC administrative law judge has accepted Consumers Power Company's open access tariff that offered both network service and point-to-point service (ER92-331, 332). In offering network service, besides allowing flexible receipt and delivery points and schedules, Consumers Power will allow flexible amounts of power as well.

Since it is offering a service that is superior in quality to the point-to-point service it will also provide under the tariff, Consumers requested that it be allowed to recover a 15 percent surcharge. It argued that NTS imposed additional costs and loss of flexibility not encountered when providing point-to-point service. FERC, as a matter of policy, should allow a higher rate for NTS service than for traditional point-to-point service to encourage the voluntary provision of the service, said the utility.

The ALJ accepted the tariff but disallowed the 15 percent adder, finding no reason to depart from traditional cost-based pricing. While agreeing that NTS is more valuable than traditional service, the judge said that FERC rarely supports value-based pricing. Further, the judge found no evidence that the utility needed an incentive to provide NTS or that NTS was more costly to provide than traditional service. The case is awaiting final FERC ruling.

The issue of unbundling transmission rates was addressed by the Commission in a case involving Northern States Power (NSP). Traditionally, for purposes of accounting and ratemaking, the Commission has attempted to maintain a boundary between what constitutes generation and transmission expenses. As long as utilities sold generation and transmission on a bundled, full requirements basis, said FERC, the actual breakdown between the two functions was not too critical. Given the increase of transmission-only services, the Commission suggested that it might make sense to reexamine its traditional approach to functionalization.

In various transmission filings consolidated into one FERC proceeding, NSP attempted to recover in transmission rates the specific costs of providing reactive support, frequency control and load dispatch, and load following services -- which have traditionally been considered generation related. In this particular case FERC accepted NSP's specific proposals for load following and rejected the utility's proposal for reactive power and frequency control because the utility offered insufficient cost support to justify

the charges. However, the Commission cautioned that if NSP wanted to refunctionalize certain generation costs to transmission, it must be prepared to accept legitimate off-setting refunctionalizations of transmission costs to production.

FERC also rejected American Electric Power Company's (AEP) attempt to recover from Public Service Indiana (PSI) and Cincinnati Gas and Electric (CG&E) the costs associated with unscheduled transmission service. At issue are transactions in which PSI and CG&E sell power to utilities in the Pennsylvania-New Jersey-Maryland Interconnection (PJM). When the transactions started in 1990, PSI and CG&E scheduled the transmission along a path that included AEP, which AEP said was appropriate since load flow studies showed that more than 95% of the power involved is carried on the AEP transmission system.

In 1991, PSI and CG&E began using another transmission path around AEP, who called the new path an abuse of the contract path method of operation. This is not an ordinary 'loop flow' problem, said AEP, which accused the parties of fashioning a sham contract path for their economic advantage. Because the transmission systems of the contract path utilities do not carry a significant amount of the power involved, said AEP, the contract path utilities were able to offer heavy discounts in their transmission rates at AEP's expense. AEP also makes up a significant amount of the losses associated with the transactions, amounting to more than \$500,000 for 1991, 1992, and the first four months of 1993.

Although AEP said that attempts to resolve the issue have proven unsuccessful, FERC told AEP to seek arbitration of the dispute, as called for in existing interconnection agreements between AEP and the parties (64 FERC 61,184). If good faith negotiations prove unsuccessful in resolving the dispute, said FERC, the Commission may select a remedy that best reflects the public interest, whether proposed by the parties or not.

FERC is also addressing issues of QF wheeling. In a case involving Western Massachusetts Electric (WMECO), FERC required the utility to file four interconnection agreements between it and a QF (61 FERC 61,182, November 3, 1992). WMECO maintained that the agreements involve interconnections with a QF, a state function; none of the agreements involve the sale or transmission of electricity necessitating FERC jurisdiction. However, FERC held, "[w]hen a utility transmits QF power in interstate commerce, as WMECO will do here, a Commission-jurisdiction transaction takes place; jurisdiction over the transmission of electric energy in interstate commerce and over agreements affecting or relating to such service (and the rates for such service) are subject to the Commission's exclusive jurisdiction." This exclusive jurisdiction over transmission in interstate commerce, said FERC, "necessitates our exercise of jurisdiction over the related interconnection costs." FERC's exclusive authority does not diminish when "facilities used to support the jurisdictional service might also be used to provide nonjurisdictional services, such as back-up and maintenance power for a QF."

FERC has also revisited the question of its ability to require utilities to provide access to QFs. Prior to the Energy Policy Act, the Commission had held that it lacked the

authority to order utilities to wheel for QFs. However, in the latest orders involving the merger between PacifiCorp and Utah Power and Light, FERC used its new section 211 authority to require the utility to extend to QFs eligibility to the transmission tariff the Commission had required in approving the merger in 1988 (62 FERC 61,018, January 14, 1993; *reh'g denied*, 62 FERC 61,235, March 12, 1993).

The EAct also gives FERC an important role in making determinations regarding the reliability impact of proposed transactions. Congress specified that FERC could not order a utility to provide access if such access would unreasonably impair reliability of affected systems, as determined by regional or national standards; it did not specify what those standards should be. Currently, the industry adheres to standards developed by the North American Electric Reliability Council (NERC). However, it is not clear as yet whether FERC will use these standards.

Retail Wheeling

Retail access is also an issue of considerable discussion. Although the EAct prohibited FERC from ordering retail access, a few states are considering the question both in the legislative and regulatory arenas. In New Mexico, an interim legislative committee was established to study and report on retail wheeling and self-service wheeling bills that had been introduced into the state legislature. The task force began hearings this August to gather background on electricity principles and utility operations. It is expected to complete its study and report to the legislature by the scheduled time of January 1995, when the legislature reconvenes.

In June, Nevada passed Senate Bill No. 231, which allows the PSC to authorize the wheeling of power to new retail loads of industries investing \$50 million, and agreeing to continue operations for 30 years. The law emphasizes state economic development and diversification of the industrial base over retail wheeling, *per se*.

..... A Massachusetts bill introduced in January 1993 would promote economic development by exempting from regulation cogenerators and small power producers selling electricity at retail to commercial and industrial customers located in state designated "economic hardship areas." While the bill does not explicitly address retail wheeling, it would require IOU and municipal utilities to provide back-up service on a non-discriminatory basis to such end-use customers served by non-utility generators. The bill is seen as possibly building a framework for future retail wheeling over utility lines to end-use customers of NUGs. However, the bill is not expected to go anywhere this year.

There is also a bill pending in the Pennsylvania legislature that would expand the authority of small municipalities to sell power from hydro projects they own or operate to any wholesale or retail user and also authorizes the Pennsylvania Energy Office to order utilities to wheel this power to retail end-users. However, no action on this bill is expected in the near-term.

The California PUC has been holding public hearings on the PUC staff report on regulatory alternatives. Two of the alternative regulatory scenarios being discussed entail retail wheeling. Commissioner Eckert said that retail wheeling is an issue parties will have to face, and a group of large industrial users supports retail wheeling. No date for a decision or other action in this undocketed matter has been set.

In Connecticut, DPUC Vice Chairman Evan Woollacott has directed staff to undertake a generic investigation of retail wheeling. The context of the inquiry, which may be opened this fall, will be the provisions of existing law allowing self-service wheeling and pressure for "economic development rates" from some of the state's large industrials.

The Illinois Commerce Commission, with the Illinois University Center for Regulatory Studies, held an open workshop 8/24/93 on "Transmission Access and Pricing: Policy and Practice in Illinois" to discuss questions of the costs/benefits, legal, regulatory and technical barriers to open access and retail wheeling. One outcome of the workshop, while not involving retail wheeling, was that major parties present agreed to attempt to work together to develop a common list of issues and to develop joint comments in the FERC transmission pricing paper proceeding. Those agreeing to attempt this included utilities, the Illinois Commerce Commission, industrial customers, and the Chicago Housing Authority.

A collaborative study of record evidence in an older but still open New York PSC retail wheeling case is being undertaken by a multi-party group called the Steering Committee on Retail Wheeling. An analysis is scheduled to be completed sometime after October 1993. A commission spokesperson was not certain at this time if a hearing on the study would be required, or if there would be an opportunity to file comments.

The Michigan Public Service Commission has initiated a public hearing and regulatory proceeding about whether to establish a retail wheeling experiment for large industrial customers. On August 27, an ALJ recommended that retail wheeling only be authorized as voluntary programs for Consumers Power Company and Detroit Edison Company. He found that the PSC has the authority to approve retail wheeling programs but not to mandate them. He found that the Energy Policy Act contains provisions that allow the PSC to approve such wheeling transactions. The ALJ also found that the retail wheeling proposals of industrials in the case had not been shown to be in the public interest, could harm other ratepayers, and did not adequately address the issues of stranded investment and utilities' obligation to serve.

TRANSMISSION PRICING

Closely tied to the issue of transmission access is pricing and the related questions of equity and priority use of the lines. FERC-ordered wheeling raises the prospect of a utility, while honoring a third party's wheeling request, being unable to make economy transactions that benefit retail customers who paid for the lines. As modified by the Energy Policy Act, section 212 of the Federal Power Act requires FERC to permit utilities to recover the full costs of providing FERC-ordered service, including all legitimate,

verifiable, and economic costs, as well as the costs of system enlargement. Costs of providing service are to be recovered from the transmission customer, and not from existing wholesale, retail, and transmission customers.

In 1992, while Congress was debating the EPAct, FERC was formulating general pricing policies for transmission service under section 205. It was attempting to address concerns that wheeling customers should compensate a utility's other customers for opportunities lost and for grid expansion when the utility provides transmission service. With passage of the EPAct, FERC Chairman Elizabeth Moler indicated that the Commission wanted to formulate one pricing policy that met the standards of both sections 205 and 211. In several recent orders, the Commission has indicated that it is studying whether the policies established in 1992 meet the statutory requirement of section 212. Chairman Moler suggested that the Commission is planning one or more technical conferences on transmission pricing; action was delayed to allow the new Commissioners to join the debate. In the meantime, the Commission has indicated that it will continue to apply its current policy in all transmission pricing cases.

Opportunity/Incremental Cost Pricing

Before 1992, transmission pricing had been based on fully-allocated, average embedded costs. However, pressure had been growing for FERC to consider other forms of pricing mechanisms that more accurately reflect the full costs of using the grid. Several requests for opportunity cost pricing of transmission were pending when, during the proceeding in the Northeast Utilities/Public Service Company of New Hampshire merger (NU/PSNH), FERC staff proposed a model that has since formed the basis of FERC's transmission pricing policy.

FERC staff suggested that the three goals of pricing policy should be to hold native load customers harmless, provide third parties with the lowest reasonable cost transmission, and prevent the collection of monopoly rents by transmission owners. The model offered pricing options that staff contended best balanced the three goals. When the system is not constrained said staff, transmission rates would be limited to embedded costs. When the system is constrained and no expansion is undertaken, said staff, transmission rates would be the higher of embedded costs or opportunity costs capped by the incremental cost of expansion needed to remove the constraint. The native load would only be harmed if opportunity costs exceeds both embedded costs and incremental costs, a situation that would be an incentive for utilities "to operate in an economically rational manner" and to expand the system, said staff. When the system is constrained and upgrades are made, rates would be the higher of embedded costs or incremental costs.

FERC issued orders in the merger and related transmission agreements (*Northeast Utilities Service Company (Re Public Service Company of New Hampshire)*, Opinion 364-A, 58 FERC 61,070; *Northeast Utilities Service Company*, 58 FERC 61,069, both January 29, 1992). FERC articulated the three goals on transmission pricing proposed by staff; a "reasonable balancing of these goals" has effectively become FERC's new standard on

appropriate transmission pricing. FERC concluded that this balancing precluded recovery of both embedded and incremental/opportunity costs. "In effect," said FERC, "the utility would be charging twice for the same transmission capacity. ... Since the utility cannot use that same capacity at the same time for two different purposes, it would be unreasonable to allow it to charge rates reflecting dual use of the same capacity."

In the merger order, which was a rehearing of an earlier order, FERC accepted the concept of including opportunity costs in rates for firm service, but declined to offer specific guidance until the compliance phase of the case. Should upgrades be made, FERC accepted the staff's proposal to allow the higher of embedded cost or incremental cost. In the transmission cases, FERC said it would allow the utility to recover out-of-rate expenses from firm customers, but declined to offer specifics until specific proposals were offered. Out-of-rate expenses are imposed by NEPOOL whenever it must deviate from economic dispatch to affect a wheeling transaction. For non-firm service, FERC allowed the utility to recover the higher of opportunity costs or embedded costs as compared on an hourly basis. It said that the availability of firm service from the merger provides non-firm customers with the ability to upgrade the service to firm and serves as a cap for the non-firm rates.

FERC expressed the willingness to depart from traditional embedded-cost pricing for transmission in *NU/PSNH*. However, in later cases implementing its new policy, FERC seemingly retreated to the point where, despite all the rhetoric, it has never allowed anybody to recover more than embedded cost calculated by traditional methods.

The first case to apply the pricing policy expounded in *Northeast Utilities* was in a QF-wheeling case involving Pennsylvania Electric (*Pennsylvania Electric Company*, 58 FERC 61,278, March 10, 1992; *Reh's Denied*, 60 FERC 61,034, July 17, 1992). FERC allowed Penelec to recover opportunity costs from transmission service but, again, only in lieu of embedded costs, despite the fact that the QF agreed to the additive approach. FERC repeated its assertion from *NU* that collecting both costs amounted to "double dipping," that is, charging twice for using the same transmission capacity. However, it noted that both Penelec's opportunity costs and incremental costs were lower than its embedded-costs. FERC found that simply charging embedded cost would leave the native-load customers better off because Penelec could charge approximately \$1 million more than its lost opportunity costs of \$200,000. Should Penelec decide to charge embedded costs and expand its system, its customers will also benefit because the utility will recover more than the expansion costs.

FERC quickly began to apply its new pricing policy to other cases. In a transmission rate filed by *Vermont Electric Power Company*, FERC dismissed with a deficiency letter the utility's attempt to recover embedded cost and incremental cost as inconsistent with its *NU* pricing policy (ER92-284, July 2, 1992). FERC also dismissed by deficiency letter an attempt by *Louisville Gas and Electric Company* to add 1 mill/kWh to the opportunity/incremental costs it would recover should these costs be greater than its standard embedded-cost rate. The utility said that the adder would allow recovery of some of its fixed costs of the transmission grid from the wheeling customer.

In the first case to apply the pricing model developed in *NU/PSNH* to NU itself, the Commission rejected NU's and New England Power Company's (NEPCO) attempt to recover the higher of embedded costs and opportunity costs on an hourly basis (61 FERC 61,009, October 2, 1992). While acknowledging that recovering the hourly approach is a form of the "or" pricing principles, the Commission contended that it violates the goal of charging the lowest reasonable cost-based rate because over longer periods the formula will exceed the higher of the two. The Commission drew a distinction between this case and the hourly comparisons it allowed for non-firm service in NU's merger-related tariffs. Although the non-firm service is reserved on a monthly basis, it is interruptible on an hourly basis. Hourly comparisons will be allowed for hourly transactions, said FERC.

The Commission also brushed aside the companies' concerns that comparing the charges over the life of the agreement would be cumbersome, would make revenues and costs uncertain until the transaction is completed, and would deprive the utilities the time value of their money. It offered a "simple calculation" that would enable the utilities to keep a running tab of the opportunity and embedded costs and allow a continuous true-up of payments. Addressing the companies' concern about having to litigate in year 10 of an agreement opportunity costs from year 1, the Commission said that the companies will identify the opportunity costs on a monthly basis, even if they are less than embedded costs; interested parties would have 90 days to challenge the calculations.

In another case involving NU, the Commission limited the ability of a utility to recover out-of-rate costs in non-firm transmission services. In *Western Massachusetts Electric Company* (WMECO), a subsidiary of NU, the Commission said that a utility could only recover those expenses that its customer, NEPCO, knows about in advance (61 FERC 61,182, November 3, 1992). FERC was unpersuaded by the arguments that WMECO will effectively be denied recovery of out-of-rate charges in most, if not all, circumstances, since they cannot be anticipated or controlled. "[T]he manner and timing of when (and even if) NEPEX notifies WMECO that units may be operated out-of-rate is not determinative of what rate is just and reasonable for service by WMECO to NEPCO." The Commission noted that its approval of opportunity-cost pricing in *Northeast Utilities* "expressly relied on the fact that customers would be afforded an opportunity *not* to incur the charge."

The specific question of incremental costs arose in a case involving Public Service Company of Colorado's (PSCO) acquisition of part of the bankrupt Colorado Ute Cooperative. In its first ruling in the case, FERC required the utility to modify the pricing provisions in accordance with FERC's pricing precedent in *Penelec* and other cases (59 FERC 61,311 June 12, 1992). The utility would not be able to recover both embedded costs and the cost of incremental upgrades needed to provide the service.

On rehearing, FERC disagreed with PSCO's contention that exceptions to the Commission's policy are warranted in several instances (62 FERC 61,013, January 13, 1993). An example is when the upgrade is added to a remote part of the transmission system where little load growth is expected and where the upgrade is used only to

provide service to the prospective wheeling customer. Further, noted PSCO, the wheeling customer may use the rest of the utility's system, imposing costs on others, such as a reduction in reliability margins or transfer capability. In these instances, the wheeling customer should pay both incremental and embedded costs, said PSCO.

"The Commission has long held that an integrated transmission grid is a cohesive network moving energy in bulk," said FERC. "Because the grid operates as a single piece of equipment, the Commission has consistently priced transmission service based on the cost of the grid as a whole. The Commission has rejected the direct cost assignment of grid facilities even if the grid facilities would not be installed but for a particular customer's service." Even though a particular customer causes a particular expansion, said FERC, "the addition represents a system expansion used by and benefitting all users due to the integrated nature of the grid." Exceptions apply only to radial lines "which are so isolated from the grid that they are and will remain non-integrated." The Commission rejected a proposal by PSCO to charge both incremental and embedded costs until the utility's other customers benefitted from the additions.

On the same day as it issued *Public Service Company of Colorado*, the Commission issued an order involving a proposal by Public Service Electric and Gas Company (PSE&G) to wheel the output of a QF to Consolidated Edison. PSE&G proposed recovering the costs it will incur to interconnect with the plant as well as the embedded cost of transmission on its system. Further, since the transaction will require it to enhance its transmission grid seven years earlier than expected, the utility proposed to charge the costs associated with having to make these modification sooner than it otherwise would have. The QF customer supported the rates.

FERC permitted the utility to recover the interconnection expenses, but only allowed recovery of the higher of embedded costs or the facilities advancement charge (62 FERC 61,014, January 13, 1993). Recovery of both would be inconsistent with the pricing policy established in *Penelec* and other cases, said FERC. Unlike earlier cases, where a utility would be providing wheeling over a constrained transmission system without expanding the system, PSE&G will be making incremental system upgrades, in the form of an acceleration of upgrades already planned. FERC said that the utility may be able to assess the full cost of these advancements, or charge a rate reflecting fully-allocated embedded cost that includes the advancements, but not both. It disagreed with the utility's argument that, by only recovering incremental costs, the customer is taking a free ride on the rest of the system. It also disagreed with the arguments that native-load customers would face higher rates if they did not recover embedded plus incremental costs and that, if the utility could only charge incremental costs, the wheeling customer would not have to pay for the cost of using the underlying system.

The Commission noted that PSE&G's incremental costs were significantly higher than its embedded costs, which seemingly would have made this case the only instance where FERC has actually allowed a utility to recover more than embedded costs. However, PSE&G's low embedded costs reflected the real novelty of the case: FERC's acceptance of a distance related, megawatt-mile formula, as opposed to the traditional

postage stamp rate. Embedded costs, as calculated under traditional, fully allocated methods, would have greatly exceeded incremental costs, leaving things pretty much as they stood before: FERC has never allowed a transmission rate to exceed embedded cost as calculated by traditional methods.

FERC offered guidance on the circumstances in which it would allow rates based on opportunity cost to breach the incremental cost cap in a ruling on the compliance filing from the NU/PSNH merger (62 FERC 61,294, March 29, 1993). NU had requested recovery of opportunity costs in excess of incremental costs if the opportunity costs are caused by unanticipated events unlikely to recur, such as multiple unit outages. The Commission rejected the request, saying that events such as multiple outages result from the utility reserving capacity on behalf of its native-load customers, who would benefit if the utility has more than is necessary, and who should, therefore, pay the costs of a capacity shortfall. Transmission customers do not cause the shortfall and should not be penalized, said FERC.

However, FERC did allow breach of the incremental cost cap if NU is diligent in building capacity. If the utility follows or beats a timetable in a study agreement to build new lines, it will be able to recover opportunity costs in excess of incremental costs. The Commission indicated that there may be other circumstances where the incremental cost cap could be breached, but the utility will have to demonstrate that the circumstances are truly exceptional.

Transmission Pricing NOI and Technical Conference

These new directions on pricing have culminated with the issuance of a Notice of Inquiry (NOI) in which FERC is taking a global review of its transmission pricing policy (RM93-19). The centerpiece of the NOI is a white paper by FERC staff on transmission pricing, discussing issues at length and including 36 questions for commenters. It includes a comprehensive overview of FERC's traditional transmission pricing policy, and an enumeration of potential revisions to that policy.

Staff suggested that FERC's traditional pricing method, postage stamp rates, does not always provide proper price signals to transmission users. Further, the Energy Policy Act (EPAct) and the emerging competition in wholesale power markets make it appropriate to reevaluate postage stamp ratemaking. Staff also suggested that a review of the contract path concept was in order, since it is a "convenient fiction" that may no longer be appropriate. Staff also examined the policy articulated in *Northeast Utilities* and *Pennsylvania Electric Company*, noting that this policy was opposed by transmission owners, some native-load customers, and some state regulators as not fully compensatory.

The FERC staff paper recommends several criteria that could be used to evaluate any transmission pricing, including a reflection of transmission constraints, incurred costs of service, actual power flows, distance or location of entry and delivery points, and the prevailing direction of flow. Staff requested comment on each of these and on whether

FERC's current policy holds native-load customers harmless and compensates the transmitter for all incurred costs. It also asks how unbundling of transmission services might affect incentives, and whether incentives could subsist if revenues are credited by state regulators to native-load customers, among other things. It also asks for comment on transition issues and costs if FERC adopts a new policy.

The paper also discusses replacing postage-stamp rates by distance-sensitive pricing, such as the MW-mile method, development of rate zones within a single utility's grid, and facility-by-facility pricing. There was also a discussion of parallel path pricing, which would compensate transmission owners for use of their grids based on the fraction of the total flow carried by each owner. Another alternative would be establishing capacity rights to the regional grid, either on a point-to-point or network-wide basis.

Comments are due November 8; reply comments December 8. Technical and policy comments on pricing issues may not exceed 50 pages. Comments on legal issues should be in a separate paper no longer than 25 pages. Reply comments should not exceed 25 pages total (in two sections if necessary). FERC said it will hold a technical conference, but the date has not been established.

Stranded Investment

FERC has also accepted the recovery of stranded investment from wheeling customers -- in principle. But, as with opportunity/incremental costs, in practice recovery of stranded investment may be difficult at best. Entergy Corporation had filed a transmission tariff in conjunction with a proposal to sell bulk power at market-based rates. Although requesting embedded cost rates for firm transmission service, Entergy also requested that a current customer using the tariff to purchase power from other suppliers be required to pay the cost of unrecovered investment. Further, should a departing customer wish to return to Entergy after leaving, Entergy may charge other than average cost of service for that "prodigal" customer to return. FERC accepted these proposals (58 FERC 61,234, March 3, 1992). It would allow Entergy to recover "legitimate and verifiable stranded investment" should facilities built to serve that customer no longer be needed when the customer uses the wheeling tariff.

However, on rehearing, FERC began to retreat by raising difficult hurdles Entergy must overcome before being able to recover stranded investment costs (60 FERC 61,168, August 7, 1992). FERC bound Entergy's eligibility for stranded investment costs by the particular circumstances existing at the time of this case. Future stranded investment problems should be addressed in termination provisions in future agreements; FERC will not accept recovery of stranded investment in a future agreement unless the agreement allows it. On what specific costs Entergy will be allowed to recover, FERC said that the company "must be able to demonstrate that it has incurred generation investments or other obligations on the customer's behalf based on a reasonable expectation at that time that the customer's power contract would be renewed. Second, the customer's cost liability for stranded investment may be no more than what the customer would have contributed to fixed costs under its existing rate had the customer remained on Entergy's

system. Third, Entergy shall mitigate a customer's stranded investment obligation when the customer leaves the Entergy system."

CONCLUSION

Implementation of the EPAct is well underway. FERC has rules in place for EWG petitions, as does the SEC for the issuance of securities by registered holding companies to finance investment in EWGs and FUCOs. Most of the states have begun work on their EPAct authority over affiliate transactions, but have not yet looked at FUCO diversification; a few have initiated procedures to implement the EPAct's PURPA standards.

On transmission, FERC has begun the process of determining what transmission information it will require utilities to submit, and it has policy statements in place on RTGs and good faith requests for service. It has acted on one transmission access request and has three requests pending. The Commission has issued and NOI its pricing policy developed in a series of FPA section 205. Until it completes its analysis, the Commission has indicated that it will continue to apply its new policy for all transmission. Under this policy, a utility can only recover the "higher of" its average embedded costs "or" its incremental/opportunity costs, not both. In practice, this has meant embedded cost pricing.