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UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C.

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FOR RELEASE ON DELIVERY
EXPECTED AT 10:00 A.M.
APRIL 23, 1982

STATEMENT OF
F. KEVIN BOLAND
SENIOR ASSOCIATE DIRECTOR, ENERGY AND MINERALS DIVISION
BEFORE THE
SUBCOMMITTEE ON ENERGY CONSERVATION AND POWER
COMMITTEE ON ENERGY AND COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

Mr. Chairman:

We appreciate this opportunity to discuss the Federal Energy Regulatory Commission's (FERC) authority to affect least cost investment strategies by utilities, the degree to which it has exercised such authority, and the limitations--especially legal--which may hinder FERC from serving as a model least cost regulator for the Nation. As you know, FERC is responsible for regulating the transmission and wholesale sales of electricity in interstate commerce, and for licensing non-Federal hydroelectric projects.

At your request, we reviewed six areas of FERC's jurisdiction relating to least cost investment: (1) rate structure and revenue requirements, (2) hydroelectric permits and licenses, (3) wheeling, (4) pooling, (5) rate approval for Federal power marketing administrations (PMA), and (6) cogeneration and small power production. Further, we looked at part of the Department of Energy's (DOE) mandated reliability study. The attachment to this testimony contains our response to specific questions you asked in your January 29, 1982, letter regarding each of the above areas. Time

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constraints prevented us from examining some aspects of FERC's actions in greater detail. While we are confident the material developed addresses your questions, we were not able, because of the tight time frame of your request, to apply the usual GAO process for ensuring the accuracy of all facts.

Our responses are based largely on our analysis of pertinent legislation; review of FERC documents, rate cases, regulations, and other materials; and interviews with FERC staff. We also contacted DOE staff and reviewed some DOE documents.

My statement today has three basic parts.

--First, a brief explanation of the concept of least cost investment strategy.

--Second, a review of FERC's statutory authorities, including those that could be used to encourage electric utility companies to adopt least cost investment strategies.

--Third, a discussion of some of the limitations in authority that reduce the probability of FERC serving as a model least cost regulator for the Nation.

LEAST COST INVESTMENT STRATEGY

In general, least cost investment strategy centers around three concepts: (1) providing electricity at the least possible cost by considering all types of generation--both conventional and nonconventional--or through movement of lower cost electricity to displace higher cost electricity, (2) reducing the need to expand generating facilities through such means as conservation, and (3) reducing or containing production costs through efficiency improvements. Because of the nature of your questions, most of our review work focused on the first two concepts.

FERC'S STATUTORY AUTHORITY AND ITS IMPLEMENTATION

FERC has authority in areas that can affect least cost investment, including rate structure, wheeling, pooling, hydroelectric licensing, cogeneration, and small power production. FERC's authority in these areas stems primarily from the Federal Power Act (16 U.S.C. 791), the Public Utility Regulatory Policies Act (PURPA) (16 U.S.C. 2601), the Department of Energy Organization Act (42 U.S.C. 7101), the National Environmental Policy Act (42 U.S.C. 4321), and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) (16 U.S.C. 839).

To date, FERC's ratemaking and other regulatory activities have not generally been oriented towards encouraging electric utilities to develop least cost investment strategies. Further, the laws under which FERC operates do not address directly the use of FERC authority to encourage least cost investment. Our preliminary legal analysis and discussions with staff of FERC's Office of General Counsel indicate that FERC has sufficient discretion in the ratemaking area to question the prudency of a utility's investment decisions--and in a few cases have actually done so--and make appropriate adjustments to a revenue increase request if it were found to be contrary to a least cost investment strategy. The end product of the ratemaking process, however, must be a just and reasonable rate. FERC can also establish ratemaking policies that will encourage or influence utilities to examine their investment decisions from a least cost perspective.

Methods of determining revenue requirements and rate designs are not geared to pursuit of a least cost strategy

FERC's rate setting authority is its principal means of influencing utility management decisions. This ratemaking process consists of two steps--first, determining the total revenues to be recovered through wholesale customer rates, and second, approving rate designs and schedules that will recover the established revenues.

FERC's approval of revenue requirements is based on determining the appropriate rate of return on the utility's invested capital and the cost of providing electric service to consumers. Although the Federal Power Act does not preclude FERC from using its rate of return determination to encourage utility management to pursue a least cost investment as long as the resulting rates are just and reasonable, it has not done so. In determining an appropriate rate of return, a zone of reasonableness within which a rate of return can equitably fall is established during the rate hearing process. Neither the boundaries of the zone nor the final rate of return approved by FERC are necessarily affected by the utility's investment practices.

FERC has not developed rate treatment policies for two cost of service elements--conservation and construction costs--that can influence a utility's least cost investment strategy. Staff in FERC's Office of General Counsel indicated that FERC has the authority to encourage utilities to pursue conservation measures through the ratemaking process. While FERC allows conservation-related costs to be included as a cost of service, it has no specific policy regarding their treatment in the ratemaking process to encourage conservation efforts. FERC uses the same standard to determine whether these costs should be included as rate base items or expensed as normal operating costs as it uses for other costs.

Rate treatment for construction work in progress (CWIP) costs is another area where FERC has legal authority to influence a utility's least cost investment strategy but FERC has not done so. FERC's current proposed rulemaking on CWIP offers criteria for determining whether a utility's financial condition is weak enough to merit including CWIP in its rate base. It does not, however, condition granting CWIP in the rate base on a showing that the investment costs are part of a least cost investment program, nor does it address whether the revenues derived from such action will be used for least cost investments.

FERC's wholesale rate design process has been primarily based on the average embedded costs of providing electric power to customers. Although not required to do so, FERC has consistently limited the revenues to be collected through a particular rate design to these average embedded costs. According to a FERC administrative law judge, this method has been tested and upheld by the courts and results in rates that meet the legislative criteria that rates be just and reasonable. This policy, however, has limited the use of full incremental or marginal cost pricing in rate schedules because more revenues would be collected under those methods than could be justified by the cost of service determination made on an average embedded cost basis.

Marginal cost-based rates, rather than average embedded cost-based rates, provide more realistic price signals of actual generation costs. In 1975, FERC issued an order encouraging utilities to submit innovative rate designs in their filing documentation to make users more aware of the real costs of electric power. Although some time-of-use and seasonally adjusted rate schedules have been approved by FERC, they resulted from agreements among the parties before reaching the Commission and, therefore, do not serve as a FERC precedent. In addition, these rates have generally been based on the average costs for meeting a particular peak load rather than on the marginal costs of providing the additional energy. No marginal cost-based rate design requests have gone through FERC's rate hearing process and been approved by the Commission, although two cases with rate design variations have gone through the hearing process and are awaiting final FERC orders.

Need for power and least cost analyses are performed for major hydropower licenses

FERC attempts to approve hydropower license applications on a demonstration that the facility is needed and that it is a least cost investment. This only occurs, however, when applications are received for projects with more than 5 megawatts of generating capacity and that involve new dam construction. This amounts to about 10 percent of FERC's license applications. While FERC performs a need for power analysis based on documentation submitted by the applicant and other available data, it rarely does an independent need for power review. It analyzes the applicant's load forecast by examining the methodology used to obtain the forecast and comparing it with other forecasts done for the region. FERC also examines the effects of conservation, load management, and rate revision on the system load.

For these larger projects, FERC also conducts an economic analysis and considers alternatives to the project to ensure that it will meet customer demand at least cost. It examines the feasibility and costs of various hydro, thermal, and nonstructural alternatives (e.g., load management and conservation) to the proposed project. If an alternative is found to be more cost effective than the proposed project, FERC staff said they would probably recommend that a license be denied.

For smaller projects, or projects where a dam already exists, less analysis is performed. FERC's main concern on these projects is that the applicant demonstrate there is a purchaser for the power.

<u>Uncertain legal status of PURPA section 210 hinders the use of qualifying facilities as part of a least cost investment strategy</u>

Section 210 of PURPA was designed to encourage the production of electricity from qualifying cogenerators and small power producers. In implementing this section, FERC published regulations requiring State regulatory authorities and nonregulated utilities to submit implementation plans by March 20, 1981. To date, all parties have not filed plans but FERC plans no further action pending the outcome of the following court cases.

Two recent court cases have jeopardized the implementation of Section 210. In one case, the Federal district court in Mississippi declared section 210 unconstitutional. This case is being reviewed by the Supreme Court. In the other case, the U.S. Court of Appeals, on January 22, 1982, ordered that FERC's "full avoided cost" rule, which determines the rate at which qualifying facilities will be paid for their power, be vacated. On March 8, 1982, FERC asked the U.S. Court of Appeals for a rehearing of this case. Until this court rules on the request, staff of FERC's Office of General Counsel said that the "full avoided cost" rule is in effect.

LIMITATIONS TO FERC
SERVING AS LEAST COST
MODEL FOR THE NATION

A number of factors, both procedural and legal, serve to limit FERC's ability to fully develop a role as the Nation's model least cost regulator of electric utilities. FERC's authority over electric rates is limited to the wholeale power market and covers only about 10 percent of all power sold. FERC staff also pointed out that while the utilities' investment strategies primarily involve generation facilities, FERC rarely has the opportunity to consider the prudency of the investment decision until the project is completed and the utility requests the costs be placed in its rate base.

The Federal Power Act places further limitations on FERC's ability to direct the utilities' investment decisions. Aside from its hydroelectric and limited cogeneration and small power production authority, FERC does not have authority to regulate matters dealing with the generation of electricity. FERC is not authorized to determine what is the best generating alternative for a utility to develop. This determination--the type and size of generation--is a critical decision for developing a least cost investment strategy. FERC is also precluded by statute from ordering utilities to form power pools, although it can influence such arrangements through its authority to approve power pool agreements and rates for power transfers.

Although recent legislation appears to broaden some aspects of FERC's authority to affect least cost investment, such legislation may be difficult to apply because it is restrictive. The PURPA amendments to the Federal Power Act concerning FERC's authority to order wheeling of electric power contain many restrictive conditions. Wheeling--providing transmission services--can be viewed as a means of moving cheaper electricity to an area to displace higher cost electricity. Wheeling is a common voluntary transaction in the electric utility industry and occurred before and after PURPA.

The PURPA amendments gave FERC authority, for the first time, to order wheeling if requested, but to date no such orders have been issued. The legislative amendments are quite restrictive: allowing only certain entities to apply to FERC for a wheeling order, not allowing FERC to issue a wheeling order on its own motion, and requiring the satisfaction of numerous complicated criteria before issuing an order. Because of these restrictions, FERC anticipates few applications for wheeling orders.

FERC's authority in PURPA dealing with pooling will probably be limited in practice. PURPA allows FERC, on its own motion or upon application, to exempt electric utilities from any provision of State law or regulation that prevents the voluntary coordination of electric utilities. PURPA may not be invoked if the State law is designed to protect public health, safety, or the environment.

FERC has not yet used this authority, and a FERC official expressed doubt that any actions would be taken under this section in the future since a State would probably link its laws to public health, safety, or the environment to preclude application of PURPA.

FERC's authority for approving Federal power marketing administration rates, as delegated to it by the Department of Energy, is too ambiguous to be easily applied. FERC is authorized to approve, on a final basis, the power and transmission rates of four power marketing administrations. Further, FERC is authorized under the Northwest Power Act to approve, on both an interim and final basis, the BPA power and transmission rates. The PMA authority, however, does not clearly define FERC's role for approving rate design, and is being questioned in several unresolved PMA rate filings.

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In summary, Mr. Chairman, we found that while FERC generally has broad authority in a number of areas that can affect a utility company's investment decisions--and which subsequently impact on electric costs--there are certain limitations which constrain its ability to directly control these investment decisions. FERC generally has not used the discretion provided in the statutes to set rates or establish policy that would encourage utilities to develop least cost investment strategies. Ratemaking procedures that have met the "just and reasonable" criteria have been developed over time and, while perhaps not totally reflective of current conditions, continue to be the standard against which new proposals are measured. Significant departures from these traditional procedures would probably be challenged in the courts and adverse rulings could further dampen FERC's ability to bring about changes. While we believe changes are possible to provide greater incentive for a least cost investment strategy by utilities, we also recognize that the constraints are real and a practical application of changes may be difficult to accomplish quickly.

This concludes my prepared statement. I will be pleased to respond to any questions you may have.

I. QUESTIONS RELATING TO FERC'S IMPLEMENTATION OF THE ELECTRIC RATE REGULATORY AUTHORITY ESTABLISHED IN PART II OF THE FEDERAL POWER ACT

A. RATE STRUCTURE ISSUES

1. In general, what is the cost basis (i.e. average embedded or incremental cost) of rate structure subject to the FERC's regulatory authority?

FERC has typically used both incremental and average embedded costs in setting utility company rates. However, the rate schedules included in rate filings that are most directly related to least cost investment strategies have generally been approved on the basis of average embedded costs.

Electric utility rate filings submitted for FERC approval can be classified into two principal categories--interconnection/coordination sales and firm power sales. Interconnection/coordination sales are transactions that generally involve two generating utility companies. The most frequent cases filed with FERC involve economy and emergency purchases of energy, energy exchanges among power pool members, and unit sales where one utility buys part of the generating capacity of another utility. Rates for these transactions are generally priced on an incremental cost basis since the costs can usually be clearly identified.

Firm power sales represent sales of energy from a generating utility to another utility for resale in the buying utility's retail market. Municipal power systems and rural electric cooperatives represent the largest group of buyers in this category. These transactions constitute the majority of cases that go through FERC's rate hearing process. Historically, these rate schedules have been based on the average embedded cost of providing electric service to a customer or class of customers. Rate schedules for

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firm power sales reflect only the amount of revenue determined necessary to cover the utility's cost of providing electric service plus a reasonable rate of return on its invested capital. Since most utilities provide a number of different types of services to their customers, the easiest method for setting rates is to apportion the total revenue needed across these various electric services on an average cost basis. This average cost method is also more easily defended as "just and reasonable" than might be the case with a different type of cost methodology.

2. Does there exist any rule or case precedent as regards the cost basis of rate structure subject to the FERC's electric regulatory authority? If so, please explain.

Numerous cases support the utilities' average cost method of establishing rate schedules. While not explicitly requiring that average costs be used in developing rate schedules, section 35.13, 18 CFR, which outlines FERC's filing requirements for changes in rate schedules, is obviously biased towards that method.

In 1975, however, FERC amended section 35.13 by issuing Order No. 537 to encourage utility companies to develop and submit innovative rate schedules based on other-than-average embedded costs. In the preamble to Order No. 537, the following statement was made:

> "Issuance of the subject filing requirements will not prejudice any party's rights, including those of our staff, to offer innovative rate design proposals through evidentiary presentations. Indeed, we believe that this matter should be examined by all electric systems with a view to determining whether alternate pricing mechanisms, particularly those based on marginal cost principles, for wholesale sales subject to the jurisdiction of this Commission would be economically sound as well as in accordance with statutory requirements."

3. Have any rate structures been approved or prescribed by the FERC which reflect, to the maximum extent practicable, system incremental demand and energy costs, as they vary by time of day or season or by volume of purchase? If so, please explain. Are any such rate structures presently under consideration by the FERC? If so, please explain their status.

Aside from the interconnection/coordination rate orders that basically reflect incremental costs of providing the electric service, FERC has approved relatively few firm power rate schedules (about 15-20) that reflect time of use rates. Furthermore, the basis for these rates has not been incremental, but average embedded cost. These cases did not go through FERC's formal hearing process but were settled, with FERC's approval, by the parties involved. This process sets no precedent and the nature of the proceeding makes it difficult to isolate the issues involved in the rate design area. Most utilities that can show variations in load between seasons of the year have approved seasonal rate schedules on file.

Several rate filings currently under consideration at FERC have rate design as one of the issues to be determined. 1/ The most significant one from a precedent-setting viewpoint is the Wisconsin Electric Power Co. (WEP) case. On July 31, 1980, WEP filed a proposed rate increase for service to 21 wholesale customers. WEP proposed a rate schedule based upon time of use, calculated through marginal-cost pricing of the energy component

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1/Wisconsin Electric Power Co. (Dockets ER 80-567 and 81-517), Northern States Power Co. (Wis.) (Docket ER 81-653), Commonwealth Edison Co. (Docket ER 79-182), Southern California Edison Co. (Dockets ER-177 and ER 79-150).

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of the rate design. The demand component 1/ of the rate design, however, was reduced below cost to meet the limitations on total revenue as determined by the cost of service as originally filed. The Wisconsin Public Service Commission has authorized this type of rate design at the intrastate retail level and supported WEP in its filing.

After some prehearing conferences, a settlement agreement was reached on all points in the filing except for rate design and transmission rates. This settlement agreement was approved by FERC on September 14, 1981. Public hearings on the rate design issue were held on October 6-8, 1981. On February 22, 1982, the assigned administrative law judge issued his initial decision on the rate design issue. In his decision, the judge found that:

(1) "* * *WEP has failed to justify the departure of its proposed rate design from a rate design patterned upon the assignment of responsibility for costs by showing any specific benefit to be expected to flow from the design which would outweigh the benefits to be expected to flow from a design based upon cost-responsibility. The design of the wholesale rates filed on this proceeding with the Settlement Agreement dated June 18, 1981, is, therefore, not just and reasonable in violation of the requirements of 16 U.S.C. 824(a) (1935)."

(2) "* * *WEP has failed to submit sufficient evidence to justify an adoption of time-of-use rates in this proceeding. In the absence of such justification, a flat-rate design, as advocated by the intervening Municipals, will be required."

1/The rate for electric power is made up of two components--demand and energy. The demand component generally consists of the annual fixed, operating, and maintenance costs of the generating plant that produces the power. The energy component generally consists of the annual fuel and variable cost of the generating plant.

The case was then sent to the Commission for final disposition. The parties to the rate hearing have 30 days to file briefs on exception and another 20 days after that to file briefs appealing the exceptions. Unless these times are extended, the Commission should have the complete record for its review by late April 1982.

In another example, the Commonwealth Edison Company submitted a filing for proposed changes in its current FERC electric service for seven of its wholesale customers on January 30, 1979. The submission contained, among other issues, time of day provisions for adjusting the energy charge for peak period use and seasonal rates to accommodate higher costs incurred during the summer months.

Commonwealth Edison proposed a time of day differential in its energy charges of 0.8222 cents per kilowatt hour (kWh). Peak hour rates would increase by 0.408 cents per kWh and rates at all other hours would decrease by 0.414 cents per kWh. The company justified the additional cost on its higher short-run, marginal costs during peak hours. The rate corresponds with the company's retail commercial and industrial time of day rates. Commonwealth Edison contended the rates would encourage conservation and efficient use of resources.

In its order setting the case for hearing, FERC suggested the use of innovative rate designs based on marginal cost "as a way of more closely matching rates to costs and thereby minimizing misallocation of resources as well as reducing waste, inequity, and discrimination." The FERC staff agreed with the utility company's use of time of day differential. Wholesale customers objected that it was not cost justified on an average cost basis and that Commonwealth Edison had not submitted a marginal cost study and peak data to support the differential. The administrative law judge found that the time of day differential in energy charges proposed by Commonwealth Edison was reasonable and justified on a marginal cost basis and would be accepted as an appropriate feature of the energy charges in the proposed rate design.

Commonwealth Edison also included a proposal in its rate filing to make demand charges higher in the summer than those in the winter. The seasonal difference amounted to about 15 percent and was intended to be an incentive for wholesale customers to limit the increase in their summer loads. FERC has approved numerous seasonally adjusted rate schedules but each rate filing must meet FERC's filing requirement for rate schedules: if the rate design is intended to reflect costs, the applicant must show how it reflects costs; if the rate design is not intended to reflect costs, the applicant must justify the departure from cost-based rates (18 CFR, section 35.13(b)(4)(iii) Statement P). In proposing the seasonal rate, Commonwealth Edison relied on the standards in the Public Utility Regulatory Policies Act of 1978 (P.L. 95-617) with respect to using seasonal rates rather than a cost-based determination. Section 111(d)(4) of the act, however, requires seasonal rates "which reflect the cost of providing service to such class of consumers at different seasons of the year to the extent that such costs vary seasonally for such utility."

After hearing the case, the administrative law judge determined that, notwithstanding FERC's filing requirement, Commonwealth

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Edison had provided no cost rationale for the 15-percent seasonal differential but chose it solely as a matter of judgement. Consequently, the judge, on June 3, 1981, rejected the company's request for a seasonal rate as not having the required cost justification. Exceptions and briefs opposing the exceptions were completed by early September. Final FERC approval of the rate filing is still pending.

The two remaining cases--Northern States and Southern California Edison--are in the beginning phases of the ratemaking process. The rate design issues are similar to, but not as significant as, the first two cases discussed.

4. Is there any legal impediment to the implementation by rule or otherwise of a policy to guide the development and submission of rate structures by utilities that, to the maximum extent practicable and consistent with otherwise existing law or policies regarding the recoupment from customers of only properly allocated average cost-based revenues, would communicate incremental costs of service to such customers? If so, please explain.

Our analysis of the applicable parts of the Federal Power Act, Department of Energy Organization Act (P.L. 95-91), the Public Utility Regulatory Policies Act of 1978 (P.L. 95-617), and discussions with FERC officials indicated no legal impediments prevent FERC from now implementing a policy for utility companies that would communicate incremental costs of service to consumers. FERC has very broad authority to prescribe the rules and regulations under which utility companies must file rate schedules, including the form in which the schedule must be filed. As part of a policy determination in this area, FERC issued Order 537 which amended the utilities' filing requirements in 18 CFR to encourage the use

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of innovative rate designs within the criteria that rates must be just and reasonable, nonpreferential, and nondiscriminatory.

Our analysis of the cases before FERC that have rate design issues involving marginal-cost pricing further indicates that FERC has a policy of accepting for filing a variety of innovative rate designs but that it will base any approval of such rate designs on the utility's compliance with the cost-justification support required in 18 CFR.

5. Please explain the manner in which rate structure is typically handled in FERC rate proceedings, including attention by the Commission, staff, and the frequency of settlement.

Electric utilities file for initial and/or revised rate schedules according to the filing requirements specified in 18 CFR, sections 35.12 and 35.13. The filing includes a proposed rate structure that will recover, through customer charges, the required revenues as determined from the filed cost of service and rate of return on invested capital.

The format generally followed in electric cases that go through the formal hearing process is as follows:

(1) The rate filing application is received, recognized in the Federal Register, and a FERC order is issued, either approving the filing or suspending it with specification as to the length of the suspension period.

(2) The assigned FERC staff prepares a "top sheet" which summarizes the staff views as to the propriety of the application.

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(3) A settlement process is initiated at which time the utility company, FERC staff, and intervenors get together and try to reach an equitable agreement on the issues in the filing.

(4) If no settlement is reached, evidence is prepared and the case goes to hearing.

(5) Briefs on the hearing are filed by the parties and the administrative law judge hearing the case writes the initial decision and sends the case to the Commission.

(6) Briefs on exceptions are filed, and the Commission makes its final decision.

The principal concern of the FERC has been that the proposed rate schedule does not allow the applicant to collect more revenues than can be justified by the cost of service analysis. The FERC staff, therefore, has tended to concentrate its efforts on analyzing the cost of service components in the rate filing and the reasonableness of the utility's requested rate of return. Less attention is usually given to the rate design proposed to collect the rates. In cases closed out by settlement agreements, the design of the proposed rates receives even less attention by the staff unless it is obvious that the rate schedule approved would be grossly unfair to consumers.

In cases that are set for formal hearing, rate designs that depart from the traditional average cost-based rates receive more scrutiny by the staff than those that follow the standard pattern. The staff may require the applicant to submit additional support

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data and will critically examine the allocation of costs between demand and energy charges. In the WEP case referred to on p. 3, for example, the staff requested sufficient additional data from the company to compute the effects of using alternative rate designs. This comparative data was then offered in staff testimony during the hearing.

Following the initial decision by an administrative law judge, the rate filing with all supporting documentation goes to the Commission. The Commission staff receives all briefs filed after the initial decision so it has the entire record to support any recommendation it may make to the full Commission on final disposition of the rate filing. During the Commission staff's review of the record, its primary function is to examine the support in the record on which the initial decision was made. Consequently, if rate design were an issue in the rate hearings, the staff would examine the support behind the judge's decision on that issue. If the Commission staff feels that the hearing record contains insufficient evidence on which a final Commisson order can be justified, the staff can recommend to the Commission that the case be sent back to the administrative law judge for further development, but this rarely occurs. In rendering a final opinion, the Commission may summarily affirm the judge's opinion. Usually, however, a new opinion is constructed which entails the meticulous rehashing of every aspect of the rate case by the staff.

The use of settlement agreements to resolve the issues in a rate filing has increased rapidly in the last 2 to 3 years. In May 1979, FERC established new administrative controls applicable to the processing of settlement agreements. Settlement proposals

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are now on a fast track and are acted on quickly. For the period January-December 1981, a total of 116 formal electric rate proceedings were initiated. Out of this total, 64 cases resulted in settlement agreements. FERC reviews settlement agreements for consistency with the public interest. Settlement agreements do not have to include all of the issues in a rate filing case and do not lead to a FERC policy on various ratemaking issues. Other than the analysis of the filing to ascertain the reasonableness of the rate schedule during the top sheet preparation, the FERC staff does very little additional work on the cases appearing to have a good chance of being settled.

Settlement agreements do not constitute a precedent for future rate filing. Consequently, one cannot use settlement agreements as an indicator of the direction FERC policy may be taking in some of the more complex rate issues. As we pointed out, a number of settlement agreements containing time of day and/or marginal cost pricing have been approved but no rate design issue with these provisions has gone through the formal hearing process and been approved by FERC. As a consequence, FERC's policy on using rate design to encourage a least cost investment strategy and to communicate the real cost of electric energy to consumers is limited to an endorsement of the concept of innovative rate designs in its rate filing requirements. The approved rate filings offer no practical guidance on solving the problem of constructing a marginal cost-based rate design that is compatible with an average cost-based revenue requirement limitation.

B. REVENUE REQUIREMENT ISSUES

1. Does the FERC consider the consistency of the purposes for which utilities will spend requested additional revenues with least cost investment strategies in determining whether an increase in rates would be consistent with provisions of the Federal Power Act? If not, is there any legal impediment to such consideration and disallowance of a rate increase request or portion thereof to the degree such increase is not shown to be necessary to implement a least cost investment strategy?

FERC generally does not consider the consistency of the purposes for which additional revenues will be spent. FERC philosophy has been, and currently remains, that the utility's management is running its company in a prudent manner and that to question the use of increased revenues requested in the rate filing would be considered as interfering in management decisionmaking. FERC staff indicated they do not want to be put in the position of "managing" a utility company. However, no legal impediment prevents FERC from examining the prudency of a utility's management decisions and adjusting rates accordingly.

The rationale for this prevailing attitude stems, in part, from the nature of Federal regulation over what is generally viewed as a very small part of the Nation's electric power system--about 10 percent of all wholesale firm power sales. The Federal Power Act also limits FERC's regulatory authority to the transmission and wholesale sales of electricity in interstate commerce. FERC was given no authority to regulate matters dealing with the generation of electricity which would normally include type, size, and location of generating units. This has been left up to the individual States. In addition, FERC has consistently maintained the

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position that it would not allow construction costs for new facilities to be placed in the wholesale rate until the project was completed and in service. 1/ As a result of these limitations, FERC views utility rate filings that include a request for increased revenues to cover capital investment costs as an after-the-fact determination of a matter that was approved by State commissions, with only the proper allocation of the cost at issue.

Although FERC has generally maintained a "hands-off" approach to questioning investment costs, we did find that FERC is beginning to depart from that position and look at utility costs from a management prudence viewpoint. For example, FERC has looked at the prudency of fuel costs, and in at least three cases 2/ examined the need for power that would be generated by plants under construction.

FERC staff told us no legal impediment prevents them from questioning the prudency of a utility's investment decisions or disallowing all or part of a revenue increase if it were found to be contrary to a least cost investment strategy. FERC has very broad discretion in fixing rates, so long as the rates are just and reasonable. This determination involves balancing the public interest with the interests of the utility company and its investors. With respect to the public's interest, the rate should not force a utility's

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1/Order 555, November 1976, modified this position to the extent that certain pollution control construction and equipment costs required by other Federal agencies would be allowed in rates as they were incurred. In addition, the order allowed FERC to consider including a utility's other construction-work-in-progress costs if a showing of severe financial distress could be made.

2/New Hampshire Public Service Co., Indiana Public Services Co., and Montaup Electric Co.

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customers to pay for costs which were not incurred in providing the public service, or to pay an unreasonable cost for the service they receive. With respect to the company's interest, the rate should yield a return reasonably sufficient to assure confidence in the company's financial soundness and a return adequate, under efficient and economical management, to maintain its credit and enable it to raise the funds necessary for the proper discharge of its public duty. In determining whether to disallow a rate increase because it will not be used for least cost investment, FERC would have to look at, among other things, how such a decision would affect service to the public and how it would affect the company's ability to operate.

FERC's legal staff, however, raises the question as to whether FERC could get enough information from the utility to support a ruling that decreased revenues were justified based on a capital investment over which FERC has no jurisdictional authority. The staff also questioned whether tangible results would accrue from such a decision unless FERC's determination was carried over into the retail part of the utility's operations and supported by the applicable State regulatory body.

2. Please describe the FERC's current and proposed policy as regards petitions for inclusion of Construction Work in Progress (CWIP) in jurisdictional rate base. In particular, please describe whether FERC's present and pending proposed regulation as regards the CWIP issue treats the matter of whether the investment as to which CWIP in the rate base treatment is sought must be shown to be part of a least cost investment program. Is there any legal barrier to the FERC requiring petitioners seeking CWIP in the rate base to demonstrate that such investment is part of a program to meet customer demand for utility-related energy services at least cost prior to the FERC initiating consideration of whether rate basing of such investment is otherwise appropriate? If so, please explain.

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Neither FERC's current order on allowing limited amounts of CWIP in a utility's rate base nor its proposed rulemaking on this issue requires a showing that the investment costs incurred for the rate relief being sought are part of a least cost investment program. Section 402(a)(1)(B) of the DOE Organization Act specifically authorizes FERC to make determinations on CWIP. Therefore, FERC could allow CWIP in the rate base on a showing that the investment costs incurred for which rate relief is being sought are part of a least cost investment program.

Since November 1976, FERC policy has permitted a utility to include CWIP in its rate base if it is related to (1) certain pollution control facilities, (2) certain fuel conversion facilities, or (3) other facilities, if the utility can show, among other things, "severe financial difficulty which cannot otherwise be alleviated without materially increasing the cost of electricity to consumers." FERC has allowed CWIP to be included under the first two circumstances, but as of March 1982, no utility has been successful in getting CWIP in rate base under the severe financial difficulty category.

In FPC Order No. 555 which established the policy, the Commission noted that, until the early 1970s, the construction period for new electric plants had been fairly short, construction costs low, and financial conditions such that the accounting and ratemaking treatment of CWIP had not been a serious financial concern to utilities. Amounts of money tied up in CWIP had been small, and the proportion of income represented by it had not been large.

According to the order, however, the significant increases in CWIP in recent years made the accounting and ratemaking treatment a matter of serious financial concern. Disallowance of CWIP in the rate base had resulted in inadequate internal cash flow to finance expansion programs and raised questions about whether utilities could obtain necessary expansion capital through new bond and/or stock issues at reasonable cost. FERC concluded that under certain circumstances, CWIP in the rate base would be justifiable. However, it also recognized that allowing CWIP in the rate base raised the issue of "intergenerational" equitability, that is, should current consumers be required to pay for costs associated with new construction which may not serve them after it goes into operation.

FERC decided that the intergenerational equity question should not prevent it from including pollution control and fuel conversion costs in the rate base. Pollution control facilities that qualify under the order include structures or portions of structures designed to reduce pollution produced by an existing generating facility; not included are facilities which lessen pollution by substituting a different, nonpolluting method of generation. Concerning fuel conversion facilities, FERC noted that national policy encouraged conversion of gas- and oil-burning plants to alternative fossil fuels. It therefore decided that fuel conversion CWIP could be included in the rate base, regardless of the specific reason for the conversion.

In accordance with Order No. 555, FERC regulations also provide a procedure for including in the rate base investments made in CWIP for purposes other than pollution control and fuel conversion. A utility must show severe financial difficulty which cannot be alleviated through other means without materially increasing consumers' cost of electricity. The Commission itself must approve the utility's request before rates based on CWIP may go into effect under the financial hardship provision. Seven CWIP cases have been submitted to FERC under this criterion. Two of these cases are in the initial review stages. In three of the cases, rate agreements were obtained without ruling on CWIP, and in the other two cases, CWIP was not allowed as a rate base item.

FERC currently has a proposed rulemaking which, for the first time, offers financial criteria for determining whether a utility is financially weak enough to merit putting CWIP into its wholesale rate base. The proposal would permit a utility to include in its rate base a portion of CWIP if (1) the utility had its bonds rated no higher than Baa by Moody's or BBB by Standard and Poor's and (2) the amount of CWIP under FERC's jursidiction which is excluded from the utility's wholesale rate base exceeds 40 percent of that rate base. The proposal does not, however, address whether the use of revenues derived from having CWIP in the rate base will be used for least cost investments in meeting service requirements.

In a report issued to the FERC Chairman, 1/ we concluded that the criteria offered in its proposal are not the major criteria FERC should consider in analyzing whether CWIP is necessary in a

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1/"Federal Energy Regulatory Commission Needs to Act on the Construction-Work-In-Progress Issue," (EMD-81-123, Sept. 23, 1981).

company's wholesale rate base. We further questioned whether these criteria should be considered at all. We believe the use of a bond rating company's evaluation should not replace an independent FERC analysis because the objectives in setting bond ratings may not be compatible with the objectives of regulation.

We recommended that the Chairman:

> "Develop a generic rulemaking for CWIP which better defines financial hardship criteria that can be applied to a utility seeking regulatory rate relief. This criteria should address how to take into consideration on a case-by-case basis a utility's current generation mix, such as, how dependent a company is on oil and gas; an analysis of a utility's demand forecast to verify that capacity expansion is, in fact, necessary; and an analysis of whether the utility is following least-cost supply options."

The FERC staff is currently analyzing the comments received on the rulemaking. The timing of the final decision on the proposal is uncertain although the Chairman expects it to be forthcoming before the end of the fiscal year.

3. Does the FERC have the authority to reduce allowed rates of return for failure of a utility to invest in efficiency measures and other alternatives that are cost-effective when compared with long-run incremental generation costs or incremental operating costs? If so, has the FERC ever done so? If not, what changes in the law would be necessary to give the FERC such authority?

Setting a rate of return on a utility's capital investment is an integral and important element in determining what a utility company's future revenue level will be. Approving a rate of return is part of FERC's ratesetting authority and no statutory barriers prevent it from establishing a rate of return that it believes will be just and reasonable. In the Federal Power Act, the Congress did not require FERC to adhere to any particular formula in its ratesetting process. It required only that the end result be just and reasonable. There is no single rate which is just and

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reasonable; rather, there is a zone of reasonableness. 1/ FERC has considerable latitude within the zone for fixing a rate of return. Presumably, FERC could set the rate of return at the lower end of the zone for a utility that failed to invest in efficiency measures. We found no examples, however, where FERC has ever reduced a utility's rate of return because the utility had failed to invest its resources as FERC thought it should.

Two major factors that could impact on this aspect of FERC's statutory authority were highlighted by the FERC staff. One factor that is common to a number of FERC's ratemaking options is the uncertainty surrounding FERC's policy on becoming more aggressive in questioning a utility's management prudency with respect to its investment and operating decisions. To make a strong case that a utility has acted imprudently requires an extensive commitment of resources and FERC has not yet made that commitment. A staff finding of imprudence would not go uncontested by the utility company and this would undoubtedly lead to extended rate hearings, increase case backlogs, and regulatory lag.

The methodology used for establishing rates of return also bears on this question. During a hearing on a rate filing, expert testimony on the rate of return issue is given by the utility company, FERC staff, and intervenors. A zone of reasonableness within which an acceptable rate of return could logically, and supportably, fall is developed. There is a substantial spread between a rate which is unreasonable because it is too low (e.g.,

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1/ FPC v. Conway, 426 U.S. 271, 278 (1976); Montana-Dakota Utility Co. v. Northwestern Public Service Co., 341 U.S. 246, 251(1951); Public Service Co. of Indiana v. FPC, 575 F. 2d 1204 (7th Cir. 1978).

a rate which is confiscatory or impairs the utility's ability to attract necessary capital) and a rate which is unreasonable because it is too high (e.g., a rate which allows the utility a return on capital not used in the public service). The zones of reasonableness established to date for any utility, have not been set based on the prudency of a utility's investment strategy.

The administrative law judge suggests a rate of return somewhere in the zone of reasonableness for FERC consideration. The Commission can accept the law judge's decision or set its own rate of return. FERC can set a rate corresponding to the particular circumstances of the case so long as the rate order produces no arbitrary result.

4. Does the FERC exercise its rate regulatory authority to the maximum extent permitted under the law so that utilities will be able to recover prudently incurred costs of conservation measures and other cost-effective alternatives to additional central station generation capacity? Does the FERC treat investments in conservation measures by utilities in any manner different from other investments? One possible disincentive to utility investment in or reliance on cost-effective efficiency improvements or generation resources furnished at least in part by its customers is that the per unit price of energy generated by the utility may have to be raised in order to enable the utility to recoup certain fixed costs formerly recouped through sales of energy that are lost. Does the FERC have any rate of return or other regulatory policy designed to overcome this disincentive? If not, why not?

FERC has no specific policy for conservation related costs but treats costs for conservation measures that the utilities submit in their rate filing in the same manner as other cost of service items. If the costs are judged to be prudent and a causal link is clearly established between the expenses and the conservation measure, they would be allowed in determining revenue requirement, either as a part of the rate base or as an expense item. FERC

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staff stated that the use of a future test year in setting a reasonable revenue requirement and the unrestricted filing privilege allows utilities to compensate for anticipated sales declines for whatever reason.

FERC has not had as much exposure to the issue of allowing conservation cost recovery through rates as have the State commissions in regulating the retail sector. The FERC staff could not recall individual cases where utilities had requested rate treatment for some of the more common conservation measures such as low or interest-free loans to customers for weatherization programs, residential time of use meters, or remote control devices for managing major household appliance usage during peak load periods. There have been several oil conversion cases, however, where FERC has allowed equipment cost recovery in the rates. In at least two cases, 1/ FERC allowed the utilities to split the fuel savings achieved by converting steam plants from oil to coal between the customers and the companies.

Other than for conservation measures related to fuel conversions, FERC's jurisdictional utilities selling energy in the wholesale market are affected by demand reductions by end-users but do not generally initiate or promote such reductions. For utilities with sufficient, or excess, generating capacity, there is little or no incentive for them to encourage further declines in energy use except possibly to reduce oil consumption. While energy consumption has declined--and growth since 1974 has declined on the average from 7 percent to 2-3 percent annually--the rate of return in the

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1/New England Power Co. & Northeast Utilities Co.

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wholesale sector has gradually increased from the 1974 level of about 10 to 11 percent to the current average of 14 to 15 percent. This increase has not been a direct policy response to the effects of conservation on a utility's fixed costs but more of a general ratemaking response to the financial difficulties many utilities have experienced in the last 6 to 8 years, including the effects of reduced demand.

The need to increase consumer rates as a result of conservation-induced decreases in demand is a current problem with some utility companies. It is difficult for utilities to resolve when (1) they are required to use historical cost data and consumption patterns to support a future revenue increase or (2) they are limited as to the timing of their rate filings. FERC has instituted the use of a future test year whereby cost and sales are estimated for the period during which the revenue increase is requested. As a result, sales declines can be anticipated and revenue increases requested so that the utility's fixed costs will be covered. Furthermore, FERC has no limitations as to how often a utility can submit a rate filing so requests for rate increases can be made on an as needed basis.

5. With respect to the FERC's policy regarding automatic adjustment clauses:

   a. Is such policy designed to assure that automatic adjustment clauses effectively provide incentives for efficient use of resources, including economical purchase of fuel and electric energy and investment in efficiency improvements where such investment is cost-effective from society's perspective?

   b. Section 205(f) of the Federal Power Act requires that the FERC "make a thorough review of automatic adjustment clauses in public utility rate schedules" not later than 2 years after the date of the enactment of section (205)(f) and not less often than every 4 years

> thereafter. Please report on the status of the FERC's compliance with this section.

Automatic adjustment clauses allow utilities to passthrough to customers certain costs of doing business without a prior hearing and have been the subject of considerable controversy since utility costs started increasing in the early 1970s. This was particularly true of automatic fuel adjustment clauses, including the cost of energy purchases. From an economic viewpoint, automatic cost pass-throughs would tend to reduce incentives for the efficient use of resources. The FERC staff contends, however, that the FERC policy, which allows for the full passthrough of purchased power costs, does offer an incentive to its jurisdictional utilities to buy power at the lowest cost. By allowing total passthrough of all costs associated with buying power from another utility, FERC believes utilities will seek out companies that can provide energy at a lower cost and will buy rather than use their own, more costly generation.

While difficult to accurately assess, a FERC statistical analysis of fuel adjustment clauses in wholesale rate schedules showed no significant effect on utility production efficiency using production cost as a measure of efficiency. FERC's analysis also showed that average coal and oil prices paid by utilities in States allowing fuel adjustment clauses were not significantly different from prices paid in States not allowing them.

In compliance with section 205(f) of the Federal Power Act, FERC has issued its first review of automatic adjustment clauses. The draft was completed May 8, 1981, and the final product was released by FERC in February 1982, considerably beyond the 2-year requirement. The study addressed four basic areas:

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--A review of all wholesale rate schedules on file at FERC with adjustment clauses classified as to form and coverage.

--An analysis of the theoretical influences on incentives for the efficient use of resources resulting from automatic adjustment clauses and statistical analyses of the available data that might indicate actual incentive effects.

--An analysis of the variability and predictability of certain costs covered under automatic adjustment clauses and rates.

--Fuel procurement practices of all major public utilities with automatic adjustment clauses and a statistical analysis to show the correlation between use of certain practices and actual fuel prices paid.

II. MATTERS RELATING TO THE FERC'S AUTHORITY UNDER PART 1 OF THE FEDERAL POWER ACT AS REGARDS THE ISSUANCE OF LICENSES AND PERMITS FOR HYDROELECTRIC FACILITIES

A. Does the FERC itself conduct an independent need for power review in conjunction with the implementation of its authority to issue preliminary permits and licenses for hydroelectric facilities under Part I of the Federal Power Act? If so, please describe this review in detail, with examples from recent cases.

FERC does not conduct an independent need for power review of proposed hydro facilities before issuing preliminary permits because most permits never result in license applications. While FERC does perform a need for power analysis, based on an applicant's submission, before issuing a license for a large project, it rarely conducts an independent need for power review. Generally, FERC assesses the need for project power only in license cases where an environmental impact statement (EIS) is required.

FERC's AUTHORITY UNDER THE FEDERAL POWER ACT

The Federal Power Act of 1935 gave the Federal Power Commission, FERC's predecessor, the authority to issue preliminary permits and licenses for all non-Federal hydro projects. Preliminary permits, issued for a period up to 3 years, guarantee a developer priority for a license application. A preliminary permit enables a developer to conduct feasibility studies on a potential hydro site and to apply for a license. Licenses, issued for a period up to 50 years, enable a developer to begin construction of a hydro project. According to section 10 of the Federal Power Act, a license can be issued only on the condition that the project

> "in the judgement of the Commission will be best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilization of water power

development, and for other beneficial public uses* * *" (16 U.S.C. 803a)

NEED FOR POWER REVIEW--PERMITS

FERC rarely examines the need for the power during the permit stage. FERC has never denied a request for a preliminary permit. FERC staff believe that a detailed analysis of a proposed project is unnecessary at the permit stage because so few permits result in requests for licenses. According to FERC's Director of Hydropower Licensing, only about 25 percent of preliminary permits actually become licenses. The remaining permits expire, usually because the proposed project would be uneconomical or because technical or environmental problems are discovered.

One case where FERC did examine the need for power issue before a preliminary permit was issued was for a proposed 3,000 megawatt pumped storage facility in Brumley Gap, Virginia. The Appalachian Power Company applied for a preliminary permit in 1977. The proposed project sparked such strong opposition from residents of Brumley Gap that FERC was reluctant to act on the permit application. Residents of Brumley Gap requested that FERC hold hearings on the permit application and hired a consultant to conduct an economic and need for power analysis of the proposed facility. According to FERC, the consultant's report 1/ contended that the proposed facility would not be needed to meet customer demand until the late 1990s or later. The Commission requested that FERC's Office of Regulatory Analysis examine and report on

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1/Report prepared by Energy Systems Research Group, Inc., Boston, Massachusetts.

the consultant's report. FERC staff stated the report basically criticized the consultant's methodology, but concluded that the need for project power at Brumley Gap was uncertain. FERC eventually decided not to hold a hearing on the permit application, and it issued a preliminary permit for the proposed project in January 1982, almost 5 years after the permit was requested.

NEED FOR POWER REVIEW--LICENSES

The generating capacity of the proposed project and whether or not an environmental impact statement (EIS) is prepared govern the detail of FERC's analysis of a hydro license application. Projects over 5 megawatts requiring environmental impact statements are analyzed in far more depth in terms of the need for power than those not requiring impact statements.

FERC's Director of Environmental Analysis decides on a case-by-case basis whether a proposed hydro facility requires an impact statement. Whether an impact statement is necessary depends on the generating capacity of the proposed project as well as the size of the dam and reservoir involved and the potential environmental impacts of the project. An EIS is generally prepared for projects involving new construction when a dam does not already exist. Impact statements are usually prepared for all proposed pumped storage and large conventional facilities since they generally entail new dam construction. Proposed projects involving the expansion of facilities with existing dams usually do not require impact statements unless they involve new land being inundated, a significant change in the reservoir level, or when significant environmental impact would result. According to the Director of Hydropower Licensing, only about 10 percent of the license applications FERC receives a year require the preparation of an EIS. Generally, FERC staff prepares only 6 to 10 impact statements a year for proposed hydro projects.

<u>Need for power review--projects not requiring an EIS</u>

The FERC staff's main concern regarding hydro projects not requiring an EIS is that the applicant demonstrate that a utility will purchase the power. In determining this, an economic analysis is conducted within the Division of Hydropower Licensing before a license is granted. FERC's position seems to be that if a utility agrees to buy the power there is little question but that the power is needed.

Further, FERC considers what type of fuel or powerplant the proposed facility would displace. According to the Director of Hydropower Licensing, many hydro projects are justified on the basis of backing out oil. In addition, FERC looks at how the power generated is to be used--including the amount of power to be used on-site, the amount of power to be sold, and the identity of the proposed purchaser(s). FERC reviews the contract between the hydro developer and the proposed purchaser to ensure that there is a market for the power. FERC may look at the applicant's plans for future development of the proposed project and at other hydro projects that exist or are planned for the service area. If the applicant submits load curves, 1/ FERC may examine them as well.

Need for power analysis--projects requiring an EIS

The preparation of an EIS requires a detailed analysis of the proposed project that addresses the need for the power to be generated, the feasibility of various hydro and thermal alternatives, and the environmental impacts of the proposed project and alternative projects. Several different groups within FERC prepare the EIS. The project manager is the Director of Environmental Analysis. The System Evaluation Branch--within the Division of Interconnection and System Analysis--conducts the need for power analysis of the project. It generally analyzes the applicant's load forecasts to ensure that the additional power is needed, although no independent forecast is prepared.

The System Evaluation Branch reviews the applicant's load forecasts from both an energy and a capacity standpoint. It examines the methodology used to obtain the load estimates to ensure that the applicant has followed state-of-the-art procedures. It compares the applicant's forecasts with other forecasts done in the State and the surrounding region to ensure that the former are reasonable. In rare cases, FERC develops its own load forecasts.

In examining the need for power issue, FERC also evaluates the effects of conservation, load management, and rate revision

1/Under FERC's regulations, applicants are not required to submit load curves unless FERC deems them necessary.

on the system load. It looks at the existing hydro and thermal power projects in the area and at those planned for the future. FERC evaluates possible hydro and thermal alternatives to the proposed project to determine if they would be better able to meet customer demand. Lastly, FERC examines the possibility of outside power purchases to determine if they would be a viable alternative to the construction of new facilities. If an alternative is found to be more cost-effective than the proposed project, FERC staff said they would probably recommend that a license be denied.

Before January 1981, the Division of Hydropower Licensing conducted all of the need for power analysis for environmental impact statements. In January 1981, this function was shifted to the System Evaluation Branch within the Division of Interconnection and System Evaluation because of staffing shortages in the Hydro Licensing group.

Although FERC usually relies on load projections of others, in one case it developed its own load forecast in analyzing a proposed project. This was for a 1,000 megawatt pumped storage facility proposed for Prattsville, New York, in 1977. The license application for the facility, filed by the Power Authority of the State of New York (PASNY), sparked strong opposition from environmental groups and from Prattsville residents. These groups requested that a hearing be held on the license application and subsequently became intervenors in the case. At the hearing, the intervenors criticized FERC's need for power analysis contained in the EIS as well as its discussion of the alternatives to the project. FERC's Office of Regulatory Analysis reexamined the need for power issue as well as the alternatives to the proposed project because FERC attorneys felt that the applicant's load growth estimates were endorsed without sufficient supporting analysis.

The Office of Regulatory Analysis (ORA) did an indepth analysis of the applicant's load growth model and developed an alternative model. The ORA found serious defects in the applicant's model and concluded that its load forecasts were not credible. ORA's own model arrived at load growth estimates that were significantly below those of the applicant.

In testimony before an administrative law judge at FERC in 1980, a staff member from the ORA asserted that the need for power generated by the facility was questionable based on the load forecasts of FERC's model and recommended that the applicant's request for a license be denied. A staff member from the Division of Hydropower Licensing who had prepared the original need for power analysis, however, refuted these assertions in his testimony at the hearing, arguing that the need for the Prattsville facility was clearly demonstrated. The Prattsville case is currently pending before an administrative law judge at FERC.

B. Does the FERC require an entity requesting a permit or a license to demonstrate need for the hydroelectric facility or to justify the facility as a necessary part of a program to meet customer demand for energy services at least cost or to file data relating to this subject?

Under FERC's regulations, entities requesting preliminary permits for hydro facilities are not required to demonstrate the need for the facility or to justify it as necessary to meet demand at least cost. The amount of information required of entities requesting hydro licenses depends on the generating capacity of the proposed project and whether it involves new dam construction. License applicants for facilities with a generating capacity under 5 megawatts are not required to demonstrate the need for the facility or to justify it as a least cost investment. Applicants for projects over 5 megawatts, on the other hand, are required to provide some information to demonstrate the need for the facility, but are not required to justify it as a least cost investment.

DATA REQUIRED FOR PRELIMINARY PERMITS

FERC requires limited information from an entity requesting a preliminary permit. Under FERC's regulations, a permit applicant is not required to demonstrate the need for the facility or to file data justifying it as necessary to meet customer demand at least cost. In the view of the FERC staff, extensive analysis of a project is unnecessary at the permit stage as many applications for permits do not result in licenses.

DATA REQUIRED FOR LICENSES

FERC has three sets of regulations governing applications for hydro licenses. One set pertains to minor projects with a generating capacity of 5 megawatts or less. A second set pertains to major projects over 5 megawatts where a dam exists; a third set pertains to major projects where new construction is involved.

Minor projects

Hydroelectric facilities with a generating capacity of 1.5 megawatts or less are considered "minor" projects. Under FERC's regulations, applicants for proposed minor projects file a short form license application. A FERC order issued in November 1980 now permits applicants for hydro projects less than 5 megawatts to file short form applications although these projects are considered "major." The short form application requires a project description, an environmental report, a water quality certificate, a list of State permits, and a list of qualifications and credentials.

Major projects--existing dams

A "major project-existing dam" is a proposed project with a generating capacity exceeding 5 megawatts that would use the water power potential of an existing dam. A "major project-existing dam" excludes any project that would result in a significant change in the surface area of a dam or that would result in "significant environmental impact." About 90 percent of the license applications FERC receives involve proposed projects with existing dams.

FERC's regulations require the applicant to submit a statement of how the project power will be used, including the amount of power to be used on-site (if any), the amount of power to be sold, and the identity of any proposed purchasers. The applicant must also submit load curves and tabular data if necessary. In addition, the applicant must file a statement of plans for future development of the project or of any other existing or proposed projects on the waterway with the estimated capacity of the proposed developments. FERC officials can request the applicant to supply any information they deem necessary and often request the applicant to submit load projections and load management data.

Concerning cost and financing, the regulations specify that the applicant provide

> "a statement of the estimated annual value of project power, based on a showing of the contract price for the sale of power or the estimated average annual cost of obtaining an equivalent amount of power (capacity and energy) from the lowest cost alternative source, specifying any projected changes in the costs of power from that source over the estimated financing or licensing period." (18 CFR 4.51(e)(5))

FERC's regulations do not require the applicant to demonstrate that the proposed project would be less costly to the consumer than other hydro or thermal alternatives.

Major projects--new construction

"Major unconstructed projects" are those which have an installed capacity greater than 5 megawatts and involve new dam construction. "Major unconstructed projects" also include those that would change the surface area of a dam or that would produce significant environmental impact. Only about 10 percent of the license applications FERC receives a year are for major unconstructed projects.

Under FERC's regulations, a license applicant for a major unconstructed project is required to submit far more detailed information regarding the need for the facility than an applicant for a project with an existing dam. The applicant must submit a statement of system and regional power needs and the manner in which the power generated is to be used, including the amount of power to be used on-site. To support this statement, the applicant must provide 1) load curves and tabular data, if appropriate, 2) details of conservation and rate design programs and their historic impacts on system loads, 3) the amount of power to be sold and the proposed purchaser(s), 4) a description of other electric energy alternatives such as gas, oil, coal, and nuclear fueled powerplants and other conventional and pumped storage plants, and 5) an evaluation of the consequences of a denial of the license and a perspective of what future use would be made of the proposed site if the project were not constructed. The applicant must also submit a statement of his plans for future development of the project or any other existing or proposed power projects on the affected waterway, indicating the estimated capacity of the proposed developments.

As with licenses for projects with existing dams, applicants must submit a statement of the estimated value of the project power based on the contract price for the sale of power or the estimated annual cost of obtaining an equivalent amount of power from the lowest cost alternative source. Applicants, as noted above, must also describe the hydro and thermal alternatives to the project. The applicant, however, is not required to discuss the costs of the alternative power projects or to demonstrate that the proposed facility is the lowest cost option. Thus, while entities requesting licenses for projects with new construction must demonstrate the need for the facility, they are not required to justify it as part of a least cost investment program.

C. Does the FERC permit intervenors to present evidence regarding need for power or justification for the facility as being part of a least cost investment strategy? If so, how? Please explain.

PROCEDURES FOR PROTEST AND INTERVENTION

Comments filed by the protestants and/or the evidence presented by intervenors may address any aspect of the proposed project including the need for power to be generated and the justification of the facility as a least cost investment. Under FERC's regulations, States, agencies, organizations, or individuals objecting to a proposed hydro facility are afforded three opportunities to file protests against the issuance of a license application. Parties may file protests: 1) after a notice of a license application is published in the Federal Register, 2) after FERC's draft environmental impact statement is issued, and 3) after FERC's final environmental impact statement is issued. For projects not requiring an EIS, protests can be filed after the notice of the license application is published in the Federal Register. Projects not requiring an EIS, however, would rarely be those likely to provoke protest or controversy.

An individual or group contesting a proposed license application may request that a hearing be held on the application and may file a petition to intervene in the case. If FERC decides to grant a hearing on a license application, the intervenor(s) may present evidence against the construction of the proposed facility at the hearing. The FERC can grant intervention even if it ultimately decides not to hold a hearing. Intervention petitions are generally rejected only if FERC feels that the interests of a prospective intervenor are already being represented by another intervenor in the case.

FERC's regulations do not address the procedures for protests of a proposed facility before a preliminary permit is issued. Generally, most requests for permits do not result in requests for licenses. In at least one case, however, for a pumped storage facility at Brumley Gap, Virginia, extensive protests of a proposed project were filed with FERC before a permit was issued (see p. 26).

OPPORTUNITY FOR COMMENT

After FERC receives a hydro license application, a notice of the application is published in the Federal Register. In addition, notices of the application are sent to appropriate Federal, State, and local officials and are usually published in State and local newspapers. After the notice of the license application is published in the Federal Register, there is a 60-day comment period in which comments, protests, or petitions to intervene may be filed.

After FERC's draft environmental impact statement (DEIS) is published and sent to the appropriate officials, there is another 45-day period in which comments, protests, and petitions to intervene may be filed. The comments FERC receives in reference to the DEIS are published and are addressed in the final environmental impact statement (FEIS) if they raise questions concerning the treatment of subject matter in the draft. Each substantive criticism of the DEIS is revised in the final impact statement.

After FERC issues its final environmental impact statement, agencies and individuals have an additional 45 days to either comment, or file protests or petitions to intervene. In its final order issuing the license or requesting that a hearing be held, FERC is required to address these comments and to evaluate any evidence that has been presented.

D. Does the FERC condition either the granting of a preliminary permit or a license under Part 1 on a demonstration that the facility for which such permit or license is sought is part of a least cost investment program to meet demand for utility-related energy services? If not, why not?

FERC does not condition the granting of a preliminary permit on a demonstration that a proposed hydro facility represents a least cost investment. FERC's position has been that since so few permits result in requests for licenses, it would be premature to undertake a detailed economic analysis of a proposed project at the permit stage. Further, FERC only conditions the granting of a license for proposed projects requiring impact statements on a demonstration that the project would be the least cost option. For less extensive projects, FERC generally does not do sufficient economic analysis to ensure that a project is a least cost investment before issuing a license. For smaller projects, there seems to be an implicit assumption among FERC staff that a hydro facility is more economical over the long run than any nonhydro alternatives.

III. MATTERS RELATING TO FERC'S AUTHORITIES REGARDING POWER WHEELING

A. Please describe in detail the FERC's implementation of the wheeling authorities set forth in sections 211 and 212 of the Federal Power Act. How many applications for a wheeling order under section 211 of the Federal Power Act have been received by the FERC? On how many such applications has the FERC acted? What is the status of each such application?

Sections 211 and 212 of the Federal Power Act give FERC authority to order wheeling only upon application from certain entities and satisfaction of numerous criteria, and not on its own motion. These provisions were added to the Federal Power Act by the Public Utility Regulatory Policies Act (PURPA).

Through February 1982, FERC had received two applications for wheeling orders. Neither has resulted in issuance of a wheeling order under sections 211 and 212. One application--from Central and Southwest Corporation--was settled before going to the full Commission, and the second application--from Southeastern Power Administration--resulted in an initial decision from the administrative law judge that the proposed transaction did not constitute wheeling under Section 211 of the act. As of late February 1982, the latter case was in FERC's Office of Opinions and Reviews awaiting a final Commission decision.

LEGAL PROVISIONS

Section 211

Section 211 allows any electric utility, geothermal power producer (including a producer which is not an electric utility), or Federal power marketing agency to apply to FERC for an order requiring any other electric utility to provide transmission services--wheeling--to the applicant.

Section 211 establishes procedures that FERC must follow before issuing an order. FERC must (1) issue a public notice, (2) issue a notice to each affected State regulatory authority, electric utility, and Federal power marketing agency, and (3) provide an opportunity for an evidentiary hearing. Further, FERC may only issue an order if it finds that the order would

--conserve a significant amount of energy, significantly promote the efficient use of facilities and resources, or improve the reliability of any electric utility system to which the order applies;

--reasonably preserve existing competitive relationships; and

--satisfy section 212 "negative test" requirements.

Section 211 also states that no order may be issued to wheel power

--already required under a contract or rate schedule,

--which provides transmission of electric energy directly to an ultimate consumer, or

--if it is inconsistent with State law governing a retail utility's marketing area.

Section 211 also provides criteria to protect the utility ordered to provide transmission services. If the original wheeling order did not establish procedures for modification/termination or did not fix the time period for wheeling, then the ordered utility can apply to FERC for terminating or modifiying the transmission services. FERC can issue such an order only after

--public notice,

--notice to affected parties,

--opportunity for evidentiary hearing,

--finding that circumstances requiring the wheeling order have changed and the termination/modification order would be in the public interest, and

--finding that the excess capacity of the wheeling utility at the time of issuance of the order, is now needed to serve its own customers.

The modification/termination order shall provide appropriate compensation and provide the affected utilities opportunity and time to make alternative arrangements and ensure that the utilities' ratepayers are protected.

Section 212

Section 212 contains still more criteria--the "negative test" criteria--to be satisfied before FERC can issue a wheeling order. No order may be issued unless FERC determines that the order

--"is not likely to result in a reasonably ascertainable uncompensated economic loss for the affected utility,"

--will not place an undue burden on the affected utility,

--will not unreasonably impair the reliability of the affected utility, and

--will not impair the ability of any affected utility to provide adequate service to its customers.

Further, section 212 mandates that the applicant for a wheeling order must show he is ready, willing, and able to reimburse the party subject to the order for reasonable costs of transmission services and a reasonable rate of return on such costs.

Before issuing a wheeling order, section 212 requires FERC to issue a proposed order and set a reasonable time for the affected parties to agree to terms and apportionment of costs. Such conditions are subject to FERC approval. If the parties agree and FERC approves the terms, the terms shall be included in the final order. If the parties do not agree within the specified time period, FERC shall set the terms in the final order. If FERC does not issue an order to wheel, FERC shall, by order, deny the application and state the reasons for denial.

STATUS OF APPLICATIONS

FERC has received two applications dealing with sections 211 and 212. One application deals only with sections 211 and 212. The other application addresses only 211 and 212 as a smaller part of its filing. Neither application has resulted in issuance of an order under these sections.

Southeastern Power Administration

On December 11, 1979, Southeastern Power Administration applied 1/ for an order under sections 211 and 212 to compel Kentucky Utilities to provide transmission services for 25 megawatts of hydroelectric power to eight municipalities.

1/Docket No. EL80-7.

On September 10, 1981, the FERC administrative law judge issued an initial decision, finding that the proposed request was denied because of the existing agreements between the parties and the amount of power involved. As of late February 1982, the case was in FERC's Office of Opinions and Reviews awaiting a final Commission decision.

Central and Southwest Corporation

On February 9, 1979, four public utilities jointly applied 1/ for (1) exemption from State regulation under PURPA section 205(a) and (2) interconnection of facilities and transmission services under parts of the Federal Power Act, including sections 211 and 212. The four utilities are wholly owned subsidiaries of Central and Southwest Corporation. As with other cases at FERC, settlement was encouraged. All parties in this case joined in the settlement agreement and/or agreed to accept the proposed order without appeal. The administrative law judge certified the settlement agreement to FERC as an uncontested offer of settlement on July 10, 1981. On October 28, 1981, an "Order Requiring Interconnection and Wheeling, and Approving Settlement" was issued.

FERC found the issuance of this order was in the public interest, would conserve a significant amount of energy, would significantly promote the efficient use of facilities and resources, would improve the reliability of each electric utility system to which the order applies and would reasonably preserve existing

1/Docket Nos. EL79-8 and E-9558.

competitive relationships. The order does not explain how these criteria are satisfied.

Settlement of this case precluded a full extensive review into FERC application of the provisions of sections 211 and 212.

B. Are the provisions of sections 211 and 212, as they require that the Commission make certain findings prior to the issuance of certain wheeling orders, a barrier to the attainment of a free market for bulk power sales in which capital and operating efficiencies are captured to the maximum extent practicable? Please explain in detail.

The provisions of 211 and 212 require that FERC determine, among other things that a wheeling order

--is in the "public interest,"

--would reasonably preserve existing competitive relationships,

--will conserve a "significant" amount of energy, and

--will not result in a "reasonably ascertainable uncompensated economic loss" for the affected utility.

According to FERC staff, these criteria do not make it easy for FERC to order a utility to wheel power. Also, no time frames are specified in the law, so that a wheeling application could be a very lengthy process. Although the legal authority to order wheeling may have initially been viewed as giving FERC more authority and as a way to provide greater movement of electricity, the statute is really quite restrictive. FERC staff do not anticipate many applications because the long list of items that must be addressed before the issuance of an order would possibly deter an applicant's hopes of obtaining an order. FERC does not anticipate issuing implementing rules, but rather will address each application on its own merits.

Wheeling is essential for electric utilities which are not geographically contiguous to engage in transactions with each other, and may also be required for utilities with remote generating sources or geographically separate service areas. Providing transmission services by one utility for another is a common, voluntary transaction in the power industry and occurred prior to and after the PURPA amendments to the Federal Power Act. Power pools use wheeling as an ordinary way of doing business. Energy brokering often requires the use of transmission lines of an intervening utility. Pooling and brokering are designed to capture capital and operating efficiencies. According to FERC the need for wheeling will become more pronounced if utilities are to increase the efficiency of their operations through pooling or other means of integration and if they are to purchase geographically distant sources of bulk power which may be economically advantageous. Wheeling is also critical during certain times of emergency, such as the 1977-78 coal strike.

The role of wheeling in helping to promote increased efficiency in the electric utility industry should be considered not only from the standpoint of its physical availability, but also from the standpoint of what are reasonable rates and terms and conditions for various wheeling services. An unreasonably high wheeling rate can be just as effective in stopping a transaction as the physical unavailability of transmission facilities.

C. Please explain the FERC's supervision of wheeling tariffs and how such tariffs are established.

FERC has authority over wheeling tariffs and wheeling rate schedules. A tariff reflects general rates, terms, charges, and conditions under which a filing utility will provide transmission service to any potential customer. A tariff does not contain or imply a contractual agreement between the filing utility and a customer, but is rather an offer to provide service. A rate schedule embodies a contractual agreement between the filing utility and a specific party and contains all the rates, terms, charges, and conditions for providing electric service to the specified party.

FERC determines the rates and terms of conditions of any wheeling service ordered if the parties involved are unable to reach an agreement among themselves. The issue of proper wheeling rates could also come before the Commission under the following categories of filings:

--A filing required under FERC regulations for certain voluntary agreements, such as those pursuant to certain interconnection and power exchange agreements.

--A court-ordered filing, such as was made by Otter Tail Power Company in Docket No. ER77-5 et al. as a result of a Supreme Court antitrust ruling.

--An agency-ordered filing, such as might be required by the Nuclear Regulatory Commission in various nuclear plant license conditions.

Section 205 of the Federal Power Act states that transmission rates shall be just and reasonable. FERC implements this statute by requiring that rates be based on costs incurred by utilities. Only jurisdictional utilities must file wheeling rates with FERC.

FERC's power pooling report 1/ states that wheeling may be affected by agreements to provide transmission services for firm power purchases, and/or economy energy agreements, a type of non-firm purchase. The typical rate for wheeling firm power is incremental cost plus some additional amount to provide an incentive to render the service or to share in the carrying charges on the facilities used to render the service. Transmission losses constitute the most significant incremental cost of wheeling. If the agreement calls for the wheeling system to deliver the same number of kWh as it receives, its principal incremental cost is the cost of generating the kWh equivalent of the losses.

On May 7, 1980, FERC issued Order No. 84, 2/ a final rule, effective June 11, 1980, placing revenue limits on the use of percentage adders 3/ in wheeling rate schedules for interchange rates. The rule establishes an administrative rule of convenience that permits a transmitting utility to charge a limit of up to one mill per kWh without submitting cost support information to

1/"Power Pooling in the United States," FERC, Dec. 1981.

2/Docket No. RM 79-29.

3/A percentage adder is a rate component that recovers revenues computed wholly or in part as a percentage of the price of purchased electric power paid by a transmitting utility for power generated by another utility.

FERC. The rule affects only rates for transmission or purchase and resale services and therefore addresses multiple party transactions. Utilities are revising their rate schedules to reflect this limit.

FERC's Office of Regulatory Analysis (ORA) estimates there are about 13 wheeling tariffs and 700-1,000 wheeling arrangements in effect. In late 1980, ORA contracted with Oak Ridge National Laboratories to review and evaluate existing and potential wheeling arrangements. The study will discuss

--how costs were determined and allocated to wheeling customers;

--how the wheeling rates were designed and determined;

--engineering, technical, and economic aspects of transmission and wheeling, their relationship to proper wheeling rates, and terms and conditions for wheeling service;

--the extent to which intermediate parties incur costs in multi-party wheeling transactions;

--the extent wheeling imposes additional operating costs on a transmission network;

--the marginal costs of providing transmission service, when needed capacity is available and when new capacity must be constructed;

--the relevance of marginal cost pricing for wheeling transactions;

--the likelihood of marginal cost pricing for transmission services leading to inadequate or excess revenues for the wheeling utility; and

--wheeling arrangements in effect by the Federal power marketing administrations.

The contract report is expected in fall 1982.

D. Please explain the FERC's authority to order the wheeling of electricity generated by qualifying cogenerators and small power producers. Have the limitations of the FERC's authority in this area prevented the development of a free market for the sale of electricity generated by such qualifying facilities? If so, please explain.

Sections 211 and 212 of the Federal Power Act do not address who can generate the power to be wheeled, but rather who can request a wheeling order. Section 210 of the Federal Power Act addresses interconnection orders. If utilities and cogenerators and small power producers are not interconnected, power cannot be wheeled.

Section 211 does not allow qualifying cogenerators and small power producers to apply to FERC for an order requiring another electric utility to provide transmission services to the applicant. An exception to this rule allows geothermal power producers that are not electric utilities to apply to FERC for a wheeling order. The provision covering geothermal producers was not part of the original section 211, but was added to section 211 with passage of the Energy Security Act of 1980. To date no geothermal producers have applied to FERC for an order.

Section 210 of the Federal Power Act allows any electric utility, Federal power marketing agency, qualifying cogenerator, or qualifying small power producer to apply to FERC for an order requiring the physical connection of any cogeneration facility, any small power production facility, or the transmission facilities of any electric utility, with the facilities of the applicant.

The rate at which a qualifying cogenerator or small power producer will be paid for its power is an important criterion to encourage the development of a free market for the sale of electricity. If a rate cannot be agreed to, there is not much need to order wheeling of power from a qualifying facility. Currently, the price for power from a qualifying facility is in question. The United States Court of Appeals on January 22, 1982, vacated FERC's rules on the use of full avoided cost to set rates for electricity from qualifying facilities. On March 8, 1982, FERC asked the Court of Appeals for a rehearing.

E. Please assess the degree to which the FERC and the DOE have accurate data regarding the degree to which power wheeling could be enhanced in the United States to capture additional efficiencies. In particular, in this assessment, please consider the implications of the findings of a report issued in September, 1981, in which the DOE Inspector General concluded that DOE's knowledge of matters relating to wheeling may not be free of industry bias because of DOE's reliance on industry data.

Neither DOE nor FERC have readily available accurate data regarding the degree to which power wheeling could be enhanced in the United States to capture additional efficiencies.

DOE'S POSITION

Wheeling and interconnection go hand in hand. Without interconnections among utilities there could be no wheeling of power. DOE's National Power Grid Study 1/ points out that, although integration, interconnection, and coordination benefits the Nation's bulk power supply system, there is substantial disagreement regarding

--how great are the benefits that remain to be captured now and in the future,

--whether these benefits will be subtantially captured during the normal evaluation of utility operations, and

--whether an accelerated evolution would be worth the economic and social costs involved.

In this report, DOE recommended that "the analytical capabilities of regulatory agencies should be enhanced and an accessible data bank should be established." DOE said that Federal and State bodies should have immediate access to essential technical data, already collected by the North American Electric Reliability Council (NERC) and other industry organizations, so they could perform independent analysis if needed. Further, DOE recommended that the NERC should participate in establishing data base standards and developing efficient mechanisms for computer-to-computer transfer of NERC data to regulatory agencies.

1/"The National Power Grid Study," U.S. Department of Energy, Jan. 1980.

This recommendation coincides with the conclusion in the DOE Inspector General's report 1/ that the electric utility industry, through NERC, provided the data on which the "Emergency Transfers" chapter of the National Power Grid Study was based. The Inspector General states that it "appears that NERC data was used since it was the only source of the data in usable form."

The analysis for the "Emergency Transfers" chapter was accomplished by using a computer model representing the eastern network transmission system projected for 1986. Base case data was obtained by running the model. DOE and NERC agreed that at no time would DOE have access to the computer model or the base case developed from the model.

FERC'S POSITION

FERC contracted with Oak Ridge National Laboratories in late 1980 to review and evaluate existing and potential wheeling arrangements. (See p. 48). One of the tasks to be addressed is to "identify alternative potential wheeling arrangements not now in existence in the United States but which might lead to improvements in existing arrangements or otherwise have significant relevance to the future needs of the electric utility industry." In addition to this contract, FERC is studying wheeling to assess the impact on wheeling tariffs and rate schedules on competition within the industry. The more restrictive a tariff/rate schedule

1/"Allegations of Industry Involvement in the Production of a Critical Chapter in the National Power Grid Study", U.S. Department of Energy, Office of Inspector General, Sept. 29, 1981.

is, the fewer number of buyers and sellers, which could potentially result in less recovery of efficiencies.

FERC's pooling report states that further coordination including coordination from wheeling would probably result in savings of 1 to 2 percent of electric revenues, on a national basis. Greater savings would probably accrue to smaller utilities. Specifically, FERC concludes

> "The aggregate unrealized economies available through further coordination to approach single-system regional planning and operation are probably not large--perhaps of the order of 1 to 2 percent of electric revenues, on a national basis. However, these economies are not uniformly distributed across systems of all sizes or all regions of the country. For small systems not now participating fully in group planning and operating coordination, the potential savings could average considerably more."

Further, the pooling study states that there is no uniform agreement on the potential extent of coordination. Specifically,

> "Utilities agree that coordination is beneficial, but there is no concensus as to its optimum extent and method."

IV. MATTERS RELATING TO FERC'S AUTHORITIES REGARDING POWER POOLING

A. Does the FERC possess any authority to order the formation of power pools?

FERC does not have authority to order the formation or dissolution of power pools. The formation of power pools in the electric utility industry is voluntary. Power pooling has evolved by means of agreements which have been mutually economical for the utilities involved. Many power pools exist in the United States. All pools have the same objectives of gaining economies of scale through the diversity of load, risks, and operating costs. How these objectives are achieved is as diverse as the number of pools. The pooling activities among utilities are influenced by public policies and regulatory authorities.

B. Please explain in detail FERC's authority to alter the conditions under which power pools operate, including tariffs, capacity expansion responsibilities, wheeling of power, attention to efficiency improvement measures, and other cost-effective alternatives to central generating stations by pool members.

Even though FERC does not possess any authority to order the formation or dissolution of power pools, it does have the authority to alter the conditions under which they operate. These authorities are: (1) section 203(a) FPA--approval of proposed mergers of vertically integrated utilities with other integrated utilities, or with small distribution systems; (2) section 202(b) FPA--ordering of interconnections; (3) section 205 and 206 FPA--jurisdiction over rates and charges (including wheeling rates), suspension of new rates, fixing rates, and costs of production; and (4) Section 205(a) PURPA--exemption of electric utilities from State law which prevents voluntary coordination.

Pools are voluntary agreements which have the objective of achieving economies of scale through the pooling of resources. Each individual pool determines how it reaches this goal.

MERGERS

Section 203(a) of the FPA requires that a public utility obtain FERC's approval before entering into a merger not involving a holding company. FERC usually approves merger applications if they are consistent with the public interest. However, FERC may attach conditions that would increase reliability and coordination. FERC developed six criteria to determine if a proposed merger is consistent with the public interest: (1) the effect of the merger on service and operating costs, (2) the effect of rates, (3) the reasonableness of the acquisition price, (4) the accounting treatment of the merger, (5) the effect of the merger on State and Federal regulatory authority, and (6) the effect the merger will have on the existing competitive situation. 1/ These tests have been adopted by FERC in past cases. 2/ Since proposed mergers are infrequent and broad public interest issues are raised in merger proceedings, it seems likely that pooling agreements among utilities will be the most common way additional coordination is achieved in the future.

1/Commonwealth Edison Company, 36 FPC (1966), Utility Users League v. F.P.C., 394 F. 2d 16(7th Cir. 1968).

2/Delmarva Power & Light Co., Docket No. El 78-10, order approving mergers (December 4, 1978).

INTERCONNECTION

Section 202(b) of the FPA gives FERC the power, upon complaint, to order interconnections between a jurisdictional utility and other entities engaged in the transmission or sale of electric energy. No FERC order requiring an interconnection can place an undue burden on a public utility or impair the utility's ability to have adequate service; neither can an order compel the enlargement of generating facilities.

RATES

FERC's regulation of power pools centers around its rate authority, found under section 205 and 206 of the Federal Power Act. "Rates" mean more than the prices charged for particular services. Rate regulation in this context includes authority over the rates, charges, classifications, and terms of service as well as pooling contracts and practices affecting particular rates. FERC has the responsibility to assure that rates under this broad context are just and reasonable and that they are not applied in a discriminatory or preferential manner.

Since the bulk power system has expanded greatly, instances of utilities being physically separated from other systems are rare. As a result of this expansion, the majority of the inter-system transmissions, sales, and exchanges of electric energy are subject to FERC's authority. Coordination arrangements between electric utility systems are among the "rates" which FERC looks at under sections 205 and 206 of the FPA.

EXEMPTION

Under section 205(a) of PURPA, FERC may, on its own or application of any person or governmental entity, exempt electric utilities from any provision of State law, rules or regulation, which prohibits or prevents the voluntary coordination of electric utilities. Action under this section of PURPA may take place after public notice to the governor of the affected State and after holding public hearings. No exemption to the State law will be granted if the rule or regulation is: (1) required by Federal law, (2) designed to protect public health, safety, or the environment, and (3) designed to conserve energy.

C. Please explain in detail how the FERC has implemented and implements its authorities regarding the formation of power pools, their disposition and the terms under which pools operate in the past and present. In particular, please specify the actions the FERC has taken under sections 205(a) and (b) of PURPA.

FERC's implementation of its authority under the FPA can alter the operating conditions of power pools. FERC has implemented its authorities by: (1) determining if pooling of electric utility resources should occur within a single corporate structure, (2) assuring a power supply on reasonable terms to utilities engaged in the distribution of energy and improving coordination between utilities producing power, and (3) expanding voluntary pooling agreements that are discriminatory.

No actions have been taken under section 205(a) of PURPA. Five regional reports and an overall pooling report have been published under the provisions of section 205(b) of PURPA.

FEDERAL POWER ACT

Section 203(a) of FPA requires that a public utility, before merging with another utility or acquiring partial acquisition of jurisdictional facilities (for example segments of transmission lines) receive the approval of FERC. In a Commonwealth Edison Company case, the Commission expressed concern over excessive utility concentration through mergers. Where large utilities have been involved, FERC usually has taken a favorable view of concentration by pooling agreements rather than through mergers, especially when competition is considered. Protection of the public interest may require FERC to consider alternatives other than those suggested by the utility. For example, FERC expressed the view in Opinion No. 57, Florida Power and Light Co., that if a utility's actions adversely affect competition, it will try to implement an alternative which is consistent with the utility's objectives.

Section 202(b) has been used in two ways. It has been used to assure a wholesale power supply on reasonable terms to utilities engaged in the distribution of electric energy. It improved mandatory coordination on a limited scale between utilities engaged in the production and sale of electric power.

The case which demonstrates FERC's authority to order coordination on reasonable terms under section 202(b) came from a 1965 application for an interconnection filed by the city of Gainesville, Florida, to interconnect with Florida Power Corporation. Before it interconnected with Florida Power Corporation, Gainesville had to operate in isolation. With the interconnection order by FERC, Gainesville and Florida Power began to share reserves and exchange a variety of coordination services. Florida Power was not opposed to the interconnection itself but was concerned about how rates were to be determined and the conditions of coordination between systems of different size. Although Gainesville might benefit proportionately more from the coordination than Florida Power Corporation, FERC rejected the position that the larger system should be compensated for the greater benefits it provides to the smaller system.

FERC's authority under section 205 and 206 of the Federal Power Act include a number of areas which influence power pooling and coordination. FERC can encourage efficient and non-discriminatory use of resources by approving the terms of power pooling agreements. This can reduce operating and investment cost, ultimately benefiting the consumer.

The New England Power Pool (NEPOOL) proceedings show how FERC has tried to bring about pooling opportunities, while allowing pool members to determine the services. NEPOOL evolved in the 1960s with New England's large investor-owned utilities seeking economies of scale. The agreement filed with FERC provided for a central dispatch of member's generation, sale and exchange of coordination services to be wheeled over pool transmission facilities, joint planning, expansion of transmission facilities and pool membership open to all regional utilities regardless of size or type of ownership. FERC approved the agreement but concluded that two provisions were discriminatory upon small systems and unlawful. These provisions were later modified by FERC.

FERC acknowledged that power pools are voluntary agreements, but these agreements are subject to public standards imposed by sections 205 and 206.

Ordinarily, FERC would have no authority to expand voluntary pooling agreements unless they have limitations that are unjust, unreasonable, unduly discriminatory or preferential. FERC, however, stated that discriminatory restrictions in membership criteria could be changed, and the benefits of coordination extended to excluded utilities. In a decision concerning the Mid-Continent Area Power Pool, FERC found that a provision requiring a system to be directly interconnected with two or more electric systems was unnecessary and discriminated against smaller systems. The FERC order stated that one interconnection was sufficient.

FERC addressed the issue of coordination for smaller systems again, when the city of Frankfort, Ky., a municipal electric distribution system directly interconnected with Kentucky Utilities Company, stated that it should be allowed to have the same coordination services which Kentucky Utilities provided to other utilities. The Commission concluded that lack of coordination imposed limitations for Frankfort to develop as a bulk power supplier. Kentucky Utilities was ordered to offer Frankfort a bilateral agreement for service.

Since pools are voluntary coordination agreements, FERC has no authority regarding the dissolution of pools. Dissolutions are approved by FERC but this is a mere formality.

For example, FERC did adopt its staff's recommendation that the provisions of the Kentucky Indiana Pool (KIP) which provided for planning functions be allowed to terminate on March 17, 1980. The agreement also provided for a variety of coordination services, which included diversity power, unit power, back-up power, emergency power, and short-term power.

In June 1976, the Public Service Company of Indiana (PSIN), one KIP pool member, filed a notice of termination of the planning functions of the pool agreement. KIP's planning functions were terminated for several reasons, according to PSIN. First, PSIN felt it was a disproportionate contributor of pool benefits. Second, PSIN decided to meet its baseload capacity expansion with nuclear powerplants. This decision was not endorsed by other members of the pool. Other pool features and service schedules will terminate as these transactions expire in the next few years. The pool members will use bilateral agreements once the KIP agreement is fully dissolved.

There are other examples of pools being dissolved. The Carolinas-Virginia pool was dissolved in 1970 basically because of disagreements over generation requirements, designation of pool transmission facilities, and pricing formulas. Efforts to create the CACTUS pool in Arizona and New Mexico terminated because of disagreements over installed reserve criteria, reserve sharing formulas, and the authority of the pool coordinator.

Section 205(a) of PURPA allows FERC to exempt electric utilities from any provisions of State law, which prohibit the voluntary coordination of electric utilities. This section may not be invoked if the State law is designed to protect public health, safety, or the environment. No action has been taken by FERC under section 205(a). A FERC official expressed doubt than any actions would be taken under this section in the future since a State would probably link its laws to public health, safety, or the environment to preclude application of section 205(a).

On February 9, 1979, four public utilities, Central Power and Light Company, Public Service of Oklahoma, Southwestern Electric Power Company, and West Texas Utilities Company--all part of a holding company, filed a joint application for exemption from state regulation preventing voluntary coordination (interconnections) across the Texas border. The holding company requested approval of four alternating current interconnections. This filing took place pursuant to section 205(a) of PURPA and sections 202, 210, 211 of the FPA.

In an attempt to settle, the holding company filed an amended application seeking approval of two direct current interconnections. All parties in the proceeding, including the State of Texas, either affirmatively joined in the settlement agreement or announced their intention to accept the proposed order without appeal. The administrative law judge certified the settlement agreement to FERC as an uncontested offer of settlement. There was no mention of section 205(a) of PURPA in the settlement agreement.

PURPA section 205(b) directs FERC to "study the opportunities for (A) conservation of energy, (B) optimization in efficiency of the use of facilities and resources and (C) increased reliability, through pooling arrangements." The Pooling report was to be issued by May of 1980.

Five regional reports were published by FERC in February 1981 as part of power pooling studies under the provisions of section 205(b) of PURPA. The reports were prepared by regional task forces consisting of regulatory and industry representatives. The regional reports reflect the work of the task forces in addressing the problems and characteristics of power pools in each region. The purpose of the task force was to assist in developing an understanding of the development, problems, benefits, status, costs, regulatory views, and other aspects of power pooling in the five regions. In addition to the regional reports, a separate report was submitted to the President and the Congress in December, 1981. This report contains an overall assessment of the status of power pooling and its future applications.

FERC is planning a follow up on its pooling report recommendations. Meetings with the regional reliability councils may take place in order to determine what kind of strategy should be used. A limited contract has been granted to a consultant to follow up on the benefits to be gained by power pooling in the Virginia-Carolinas subregion.

V. MATTERS RELATING TO FERC'S AUTHORITIES REGARDING FEDERAL POWER MARKETING ADMINISTRATION RATES

A. Please set forth in detail the FERC's authority as it relates to the rates and rate designs of the five Federal power marketing administrations. What limitations exist in such authority to prescribe rates and rate structures for such adminstrations?

FERC'S AUTHORITIES

FERC's authority relating to rates of the five Federal power marketing administrations 1/ (PMA) stems from the (1) Department of Energy (DOE) Delegation Order 0204-33 and (2) Pacific Northwest Electric Power Planning and Conservation Act of 1980, (Northwest Power Act) (P.L. 96-501). FERC is authorized to approve the final rates for four PMAs and to approve both the interim and final rates for Bonneville Power Administration (BPA). Both FERC and DOE agree that FERC rate authority should be concerned that PMA revenue requirements sufficiently recover capital costs and repay the Federal investment within a reasonable time period. FERC must also determine if the rates encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. According to FERC, its PMA rate design authority is being decided on a case-by-case basis.

In a March 3, 1982, appearance before the Subcommmittee on Energy and Water Development, House Appropriations Committee, FERC's chairman, in responding to questions, indicated that FERC

1/The five Federal power marketing administrations are Alaska Power Administration, Bonneville Power Administration, Southeastern Power Administration, Southwestern Power Administration, and Western Area Power Administration.

didn't need the PMA rate approval authority since it somewhat duplicated DOE's development of the rates. Further, the chairman asserted that FERC didn't need to protect the consumer from unreasonably high rates since PMA rates have traditionally been on the low side.

Before the creation of DOE in 1977, the Federal Power Commission and the Department of the Interior were responsible for the establishment, confirmation, and approval of the Federal PMA rates. The Department of Energy Organization Act (P.L. 96-91) transferred these functions to the Secretary of Energy, who in turn delegated confirmation and approval authority of PMA rates to the Administrator of the Economic Regulatory Administration. PMA rate authorities were shifted in 1979 to FERC and the Assistant Secretary for Resource Applications.

Delegation Order

DOE Delegation Order 0204-33, effective January 1, 1979, delegated to the DOE Assistant Secretary for Resource Applications 1/ the authority to develop PMA power and transmission rates and to confirm, approve, and place in effect such rates on an interim basis. The delegation order also assigned to FERC the authority to confirm and approve PMA power and transmission rates on a final basis or to disapprove the rates developed by the Assistant Secretary

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1/The authority was transferred from the Assistant Secretary for Resource Applications to the Assistant Secretary for Conservation and Renewable Energy on March 19, 1981, as a result of the former position being abolished and the creation of the Office of Assistant Secretary for Conservation and Renewable Energy.

for Resource Applications. FERC does not have the authority to modify rates. FERC views its role as an appellate one--to affirm, reverse, or remand the rates submitted to it for final review.

The delegation order is general in scope, and does not delineate the methodology, time frame, or areas to be covered in FERC's approval/disapproval process. No specific mention of rate design is made in the delegation order. To date, FERC has not issued rules on the contents of a PMA rate filing or the steps FERC staff take to analyze an application. PMA's must file what they think is adequate.

Two ongoing BPA rate cases 1/ initiated before passage of the Northwest Power Act raise questions on FERC's rate design authority but not rate authority. Both BPA and FERC agree that FERC should assure that rates sufficiently recover capital costs and repay the Federal investment within a reasonable time period, while also encouraging wide use of electric power at the lowest cost to consumers. BPA interpreted FERC remand orders in these cases as requesting information on rate design. BPA claims in its response to the remand orders that FERC should not be involved in rate design; rate design is the authority of BPA. BPA states that the Commission has traditionally not been involved with rate design functions. BPA goes further to quote the former FERC

1/Docket No. E-9563 and EF 80-2011.

2/GAO issued a report "Policies Governing the Bonneville Power Administration's Repayment of Federal Investments Need Revision" (EMD-81-94, June 16, 1981) which discusses BPA's repayment of the Federal investment.

Director of Electric Power Regulation (during hearings on what became the Northwest Power Act) as concurring with BPA's position that FERC should not be involved with rate design:

> "It should be noted that the Commission does not have the authority to fix rates, design rates, or to specify which customer should be served by the Federal projects. These responsibilities have been assigned to the Assistant Secretary for Resource Applications (AS/RA) and to the PMAs."

These two BPA cases are under review at FERC. According to FERC, its PMA authority is being decided on a case-by-case basis. No one is taking a broad overall look at FERC's PMA rate design authority. FERC staff also indicated that two other pending BPA cases and one pending Western Area Power Administration case also touch on the rate design issue.

Northwest Power Act

Section 7 of the Northwest Power Act, passed December 5, 1980, provides FERC with specific statutory authority for rate approval of BPA. The act gives FERC responsibility for approving BPA rates on both an interim and final basis. The law does not mandate the time frames involved in FERC's approval process or change the responsibility for developing and establishing BPA rates; it remains with the BPA Administrator.

Rates become effective on a final basis only upon FERC's confirmation and approval, based on a finding that the rates

"(A) are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs,

(B) are based upon the Administrator's total system costs, and

(C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system."

The act provides an exception to FERC's approval of interim rates for BPA. The act authorizes FERC to establish procedures by December 5, 1981, to approve the final rate submitted by BPA on an interim basis. Pending the establishment of these procedures, the Secretary of Energy can approve BPA rates on an interim basis. These rates can remain in effect until July 1, 1982. During this 1-year period, the DOE Assistant Secretary for Conservation and Renewable Resources granted interim approval for various rate schedules to become effective on an interim basis July 1, 1981.

On December 4, 1981, FERC issued an interim rule to establish procedures for the interim acceptance of rates submitted by BPA. The interim rule provides (1) general procedures, (2) filing requirements, and (3) standards for FERC rate review. According to FERC, it is establishing procedures primarily to standardize the rate filing and approval procedure and to provide sufficient notice of FERC requirements. Among other things, the interim rules require BPA to submit some information on rate structures. Specifically, the filing must contain (1) a description of how the filed rate differs in rate level or rate structure from the existing rate schedule in effect, and (2) a description of any methodology used for determining revenue requirements and for developing appropriate rate structures. The rule, effective December 4, 1981, was promulgated on an interim basis and subject to notice and comment procedures before approval on a final basis. Comments were due by February 5, 1982. As of the end of February, FERC is currently reviewing the comments.

Conflict exists over the scope of FERC's authority to review rate design and interclass cost allocations under the Pacific Northwest Act. Consequently, in January 1982, FERC issued an order requesting interested parties to present briefs by late February 1982 on the extent of FERC's review authority. FERC is in the process of reviewing the comments.

B. Please explain in detail how the FERC has implemented this authority with respect to each power marketing administration.

FERC's authorities for PMA rates became effective January 1, 1979. FERC statistics indicate that between January 1979 and January 1982, FERC approved 15 PMA rate applications and 10 rate applications are pending. The table below catagorizes these cases by PMA.

PMA	No. Rate Applications	Status Approved	Status Pending
Western area	5	1	4
Southeastern	9	7	2
Southwestern	5	5	0
Alaska	2	2	0
Bonneville	4	0	4
	25	15	10

During this 3-year period, FERC remanded three rate filings, (two Bonneville and one Southwestern), which are not included in the above chart. However, these three rate applications were revised and refiled and are included in the above chart. The one Southwestern case was finally approved, but the two Bonneville cases are still pending.

Listed below is a table on PMA cases completed each fiscal year since FERC was authorized PMA approval responsibility.

Fiscal year	Filings approved	Cases pending or remanded
1979	1	-
1980	2	-
1981	10	3
1982 (thru 2/1/82)	2	10
	15	13

VI. MISCELLANEOUS MATTERS

A. How does the FERC interpret the requirement of section 102(2)(c)(iii) of the National Environmental Policy Act (NEPA) as it affects need for power/least cost determinations relating to hydro-electric facilities?

Under section 102(2)(c)(iii) of the National Environmental Policy Act of 1969 (NEPA), all Federal agencies are required to

> "include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on* * * alternatives to the proposed action* * *"

To comply with this section of NEPA, FERC evaluates the feasibility of various alternatives to proposed hydro facilities with a generating capacity over 5 megawatts before issuing a license. As noted on page 29, FERC does a fairly extensive analysis of alternatives to proposed facilities that require the preparation of an environmental impact statement (EIS). Generally, all proposed hydro projects that involve new dam construction or that would produce significant environmental impact of any kind, require environmental impact statements. FERC's Director of Environmental Analysis determines which proposed projects require the preparation of an EIS on a case-by-case basis.

In an environmental impact statement, FERC discusses the feasibility of alternatives such as power purchases, conservation, rate revision, load management, and alternative hydro designs and sites to the proposed facility. It also discusses various thermal alternatives and a "no action" alternative. FERC describes how each of the alternatives either would or would not be able to meet the load requirements of the applicant's service area. FERC then selects the most reasonable alternative(s) to the proposed action and does an economic analysis and comparison of the alternative(s) and the proposed facility. Generally, FERC calculates the benefits and costs of a proposed project and its most reasonable alternative(s) by using a 50-year present worth analysis. FERC, in addition, compares the environmental impacts that are likely to result from the proposed action and the most reasonable alternative(s).

FERC is complying with the requirement set forth in the National Environmental Policy Act that a Federal agency include a detailed statement of the alternatives to proposed actions that would significantly affect the quality of the environment.

B. Section 210(h)(2)(A) of PURPA authorizes the FERC to enforce its rules respecting qualifying cogenerators and small power producers. Please report on the FERC's implementation of this provision.

Section 210 of PURPA was designed to encourage cogeneration and small power production of electric energy. FERC published implementing regulations requiring State regulatory authorities and nonregulated electric utilities to submit implementation plans to FERC by March 20, 1981. Fifty State regulatory authorities and about 2,200 nonregulated utilities were required to file.

By March 20, 1981, only six States had submitted plans. FERC took no immediate action to pull the other States and nonregulated utilities into compliance, even though section 210(h)(2)(A) of PURPA grants FERC enforcement authority. Between November 1981 and February 1982, FERC issued letters to States and nonregulated utilities informing them of their delinquency and requesting compliance. FERC statistics indicate that as of February 5, 1982:

--27 States had filed complete implementation plans.

--17 States had filed progress reports and have plans nearing completion.

--6 States have not filed anything with FERC.

--978 nonregulated utilities had filed.

Two court cases--the Mississippi case and the American Electric Power (AEP) case--have hindered FERC's enforcement policy. Both of these cases are still pending. FERC staff indicated it will not take enforcement action against noncomplying States and utilities until these cases are settled.

On February 20, 1981, the Federal district court in Mississippi declared section 210 of PURPA unconstitutional. FERC appealed this case to the Supreme Court, where hearings were held in January 1982. FERC is awaiting the Court's decision, expected around June 1982.

On January 22, 1982, the United States Court of Appeals issued its decision in the American Electric Power Service Corporation vs. FERC case. The judge ordered that FERC's "full avoided cost" rule be vacated. It was this rule that determined the rate at which qualifying facilities would be paid for their power. On March 8, 1982, FERC asked the Court of Appeals for a rehearing. Until this court rules on the request, staff of FERC's Office of General Counsel has said that the "full avoided cost" rule is in effect.

C. Section 209 of PURPA requires that the Secretary of Energy conduct a study with respect to electric system reliability in the United States. Section 209(a)(2) requires that the Secretary consider six issues relating to reliability including:

(D) alternatives to adding new generation facilities to achieve desired levels or reliability (including conservation);

(E) the cost-effectiveness of adding a number of small, decentralized conventional and nonconventional generating units rather than a small number of large generating units with a similar total megawatt capacity for achieving the desired level of reliability.

Please report whether the Secretary has complied with the requirement to consider these six issues, particularly those set forth in paragraphs (D) and (E) above, and indicate the manner in which the matters raised in paragraphs (D) and (E) were considered.

In response to the mandate of section 209 of PURPA, a study was done by DOE's Utility Systems and Emergency Communications Division. The report consists of an executive summary, a final report, and technical study reports. The reports comply with the requirement to consider the six issues addressed in section 209(a)(2) of PURPA. Issues (D) and (E) (alternatives to adding new generation and the cost-effectiveness of adding small, decentralized units vs. large units) are covered both in the final report and the technical study reports. A DOE official stated that several problems emerged in the collection of data and the writing of the report. The difficulties were: (1) no consensus on what the Congress wanted, (2) the request was very broad in scope, and (3) in some instances what was asked was beyond the capability of DOE, because the data was not available.

Issues (D) and (E) are covered in chapter 7 "Planning and Operating" of the final report. Specifically, there is a discussion on generation system reliability on pages 72-74. This discussion includes: (1) generation system characteristics, (2) generating unit characteristics; (3) small versus large units, (4) conventional versus nonconventional technologies, and (5) central versus decentralized generation.

The technical study addresses issues (D) and (E) in chapter 2, "Alternative Methods for Achieving Given Power System Reliability Levels." This chapter examines the relative cost-effectiveness of competing electrical generating alternatives in contributing to the overall reliability level of a utility system. Three principal issues raised by PURPA are considered. When additional generating is needed, is it cost-effective to: (1) use small unit sizes rather than fewer large units of similar total megawatt capacity, (2) use intermittent and conventional generating units in place of nonconventional units, and (3) use generation in decentralized rather than centralized applications.

The DOE technical study results showed that the cost-effectiveness of alternative generation technologies in achieving a desired level of system reliability depends on the mix of existing generation and the projected load to be served. The small, dispersed nonconventional power generation technologies were found to be less cost-effective than some of the conventional technologies. The primary reason is that the capital costs of these units are too high for the amount of energy cost they provide.