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PRIVATE POWER LAWS AND REGULATIONS ON RENEWABLE ENERGY TECHNOLOGIES

Prepared for:

The Indian Minister for Non-Conventional Energy Resources (MNES)

Prepared by:

The Private Sector Energy Development (PSED) Program Under The India Private Power Initiative (IPPI) of the United States Agency for International Development (USAID)

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DISCLAIMER

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TAB 1

Public Utility Regulatory Policies Act

PUBLIC UTILITY REGULATORY POLICIES ACT

October 10, 1978.—Ordered to be printed

Mr. Staggers, from the committee of conference, submitted the following

CONFERENCE REPORT

[To accompany H.R. 4018]

The committee of conference on the disagreeing votes of the two Houses on the amendment of the House to the amendment of the Senate to the bill (H.R. 4018) entitled "An Act to suspend until the close of June 30, 1980, the duty on certain doxorubicin hydrochloride antibiotics", having met, after full and free conference, have agreed to recommend and do recommend to their respective Houses as follows:

That the Senate recede from its disagreement to the amendment of the House to the amendment of the Senate to the text of the bill and agree to the same with an amendment as follows:

In lieu of the matter proposed to be inserted by the House amendment insert the following:

SECTION 1. SHORT TITLE AND TABLE OF CONTENTS.

(a) Short Title.—This Act may be cited as the "Public Utility Regulatory Policies Act of 1978".

(b) Table of Contents.—

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SEC. 2. FINDINGS.

The Congress finds that the protection of the public health, safety, and welfare, the preservation of national security, and the proper exercise of congressional authority under the Constitution to regulate interstate commerce require—

(1) a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers,

(2) a program to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of wholesale rate applications before the Federal Energy Regulatory Commission, the participation of the public in matters before the Commission, and to provide other measures with respect to the regulation of the wholesale sale of electric energy,

(3) a program to provide for the expeditious development of hydroelectric potential at existing small dams to provide needed hydroelectric power,

(4) a program for the conservation of natural gas while insuring that rates to natural gas consumers are equitable,

(5) a program to encourage the development of crude oil transportation systems, and

(6) the establishment of certain other authorities as provided in title VI of this Act.

SEC. 3. DEFINITIONS.

As used in this Act, except as otherwise specifically provided—

(1) The term "antitrust laws" includes the Sherman Antitrust Act (15 U.S.C. 1 and following), the Clayton Act (15 U.S.C. 12 and following), the Federal Trade Commission Act (15 U.S.C. 41 and following), the Wilson Tariff Act (15 U.S.C. 8 and 9), and the Act of June 19, 1936, chapter 592 (15 U.S.C. 13, 13a, 13b, and 21 A).

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(2) The term "class" means, with respect to electric consumers, any group of such consumers who have similar characteristics of electric energy use.

(3) The term "Commission" means the Federal Energy Regulatory Commission.

(4) The term "electric utility" means any person, State agency, or Federal agency, which sells electric energy.

(5) The term "electric consumer" means any person, State agency, or Federal agency, to which electric energy is sold other than for purposes of resale.

(6) The term "evidentiary hearing" means—

(A) in the case of a State agency, a proceeding which (i) is open to the public, (ii) includes notice to participants and an opportunity for such participants to present direct and rebuttal evidence and to cross-examine witnesses, (iii) includes a written decision, based upon evidence appearing in a written record of the proceeding, and (iv) is subject to judicial review;

(B) in the case of a Federal agency, a proceeding conducted as provided in sections 554, 556, and 557 of title 5, United States Code; and

(C) in the case of a proceeding conducted by any entity other than a State or Federal agency, a proceeding which conforms, to the extent appropriate, with the requirements of subparagraph (A).

(7) The term "Federal agency" means an executive agency (as defined in section 105 of title 5 of the United States Code).

(8) The term "load management technique" means any technique (other than a time-of-day or seasonal rate) to reduce the maximum kilowatt demand on the electric utility, including ripple or radio control mechanisms, and other types of interruptible electric service, energy storage devices, and load-limiting devices.

(9) The term "nonregulated electric utility" means any electric utility other than a State regulated electric utility.

(10) The term "rate" means (A) any price, rate, charge, or classification made, demanded, observed, or received with respect to sale of electric energy by an electric utility to an electric consumer, (B) any rule, regulation, or practice respecting any such rate, charge, or classification, and (C) any contract pertaining to the sale of electric energy to an electric consumer.

(11) The term "ratemaking authority" means authority to fix, modify, approve, or disapprove rates.

(12) The term "rate schedule" means the designation of the rates which an electric utility charges for electric energy.

(13) The term "sale" when used with respect to electric energy includes any exchange of electric energy.

(14) The term "Secretary" means the Secretary of Energy.

(15) The term "State" means a State, the District of Columbia, and Puerto Rico.

(16) The term "State agency" means a State, political subdivision thereof, and any agency or instrumentality of either.

(17) The term "State regulatory authority" means any State agency which has ratemaking authority with respect to the sale of electric energy by any electric utility (other than such State agency), and in the case of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority, such term means the Tennessee Valley Authority.

(18) The term "State regulated electric utility" means any electric utility with respect to which a State regulatory authority has ratemaking authority.

SEC. 4. RELATIONSHIP TO ANTITRUST LAWS.

Nothing in this Act or in any amendment made by this Act affects—

(1) the applicability of the antitrust laws to any electric utility or gas utility (as defined in section 302), or

(2) any authority of the Secretary or of the Commission under any other provision of law (including the Federal Power Act and the Natural Gas Act) respecting unfair methods of competition or anticompetitive acts or practices.

TITLE I—RETAIL REGULATORY POLICIES FOR ELECTRIC UTILITIES

Subtitle A—General Provisions

SEC. 101. PURPOSES.

The purposes of this title are to encourage—

(1) conservation of energy supplied by electric utilities;

(2) the optimization of the efficiency of use of facilities and resources by electric utilities; and

(3) equitable rates to electric consumers.

SEC. 102. COVERAGE.

(a) VOLUME OF TOTAL RETAIL SALES.—This title applies to each electric utility in any calendar year, and to each proceeding relating to each electric utility in such year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(b) EXCLUSION OF WHOLESALE SALES.—The requirements of this title do not apply to the operations of an electric utility, or to proceedings respecting such operations, to the extent that such operations or proceedings relate to sales of electric energy for purposes of resale.

(c) LIST OF COVERED UTILITIES.—Before the beginning of each calendar year, the Secretary shall publish a list identifying each electric utility to which this title applies during such calendar year. Promptly after publication of such list each State regulatory authority shall notify the Secretary of each electric utility on the list for which such State regulatory authority has ratemaking authority.

SEC. 103. FEDERAL CONTRACTS.

Notwithstanding the limitation contained in section 102 (b), no contract between a Federal agency and any electric utility for the sale *of electric energy by such Federal agency for resale which is entered into or renewed after the date of the enactment of this Act may contain any provision which will have the effect of preventing the implementation of any requirement of subtitle B or C. Any provision in any such contract which has such effect shall be null and void.*

Subtitle B—Standards for Electric Utilities

SEC. 111. CONSIDERATION AND DETERMINATION RESPECTING CERTAIN RATEMAKING STANDARDS.

(a) CONSIDERATION AND DETERMINATION.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title. For purposes of such consideration and determination in accordance with subsections (b) and (c), and for purposes of any review of such consideration and determination in any court in accordance with section 123, the purposes of this title supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

(b) PROCEDURAL REQUIREMENTS FOR CONSIDERATION AND DETERMINATION.—(1) The consideration referred to in subsection (a) shall be made after public notice and hearing. The determination referred to in subsection (a) shall be—

(A) in writing,

(B) based upon findings included in such determination and upon the evidence presented at the hearing, and

(C) available to the public.

(2) Except as otherwise provided in paragraph (1), in the second sentence of section 112(a), and in sections 121 and 122, the procedures for the consideration and determination referred to in subsection (a) shall be those established by the State regulatory authority or the nonregulated electric utility.

(c) IMPLEMENTATION.—(1) The State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or nonregulated electric utility may, to the extent consistent with otherwise applicable State law—

(A) implement any such standard determined under subsection (a) to be appropriate to carry out the purposes of this title, or

(B) decline to implement any such standard.

(2) If a State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or nonregulated electric utility declines to implement any standard established by subsection (d) which is determined under subsection (a) to be appropriate to carry out the purposes of this title, such authority or nonregulated electric utility shall state in writing the reasons therefor. Such statement of reasons shall be available to the public.

(d) ESTABLISHMENT.—The following Federal standards are hereby established:

(1) COST OF SERVICE.—Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs by providing electric service to such class, as determined under section 115(a).

(2) DECLINING BLOCK RATES.—The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class which costs are attributable to such energy component decrease as such consumption increases during such period.

(3) TIME-OF-DAY RATES.—The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis which reflects the costs of providing electric service to such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class, as determined under section 115(b).

(4) SEASONAL RATES.—The rates charged by an electric utility for providing electric service to each class of electric consumers shall be on a seasonal basis which reflects the costs 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.

(5) INTERRUPTIBLE RATES.—Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which such consumer is a member.

(6) LOAD MANAGEMENT TECHNIQUES.—Each electric utility shall offer to its electric consumers such load management techniques as the State regulatory authority (or the nonregulated electric utility) has determined will—

(A) be practicable and cost-effective, as determined under section 115(c),

(B) be reliable, and

(C) provide useful energy or capacity management advantages to the electric utility.

SEC. 112. OBLIGATIONS TO CONSIDER AND DETERMINE.

(a) REQUEST FOR CONSIDERATION AND DETERMINATION.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility may undertake the consideration and make the determination referred to in section 111 with respect to any standard established by section 111(d) in any proceeding respecting the rates of the electric utility. Any participant or intervenor (including an intervenor referred to in section 121) in such a proceeding may request, and shall obtain, such consideration and determination in such proceeding. In undertaking such consideration and making such determination in any such proceeding with respect to the application to any electric

utility of any standard established by section 111(d), a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or nonregulated electric utility may take into account in such proceeding—

(1) any appropriate prior determination with respect to such standard—

(A) which is made in a proceeding which takes place after the date of the enactment of this Act, or

(B) which was made before such date (or is made in a proceeding pending on such date) and complies, as provided in section 124, with the requirements of this title; and

(2) the evidence upon which such prior determination was based (if such evidence is referenced in such proceeding).

(b) TIME LIMITATIONS.—(1) Not later than 2 years after the date of the enactment of this Act, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to each standard established by section 111(d).

(2) Not later than 3 years after the date of the enactment of this Act, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by section 111(d).

(c) FAILURE TO COMPLY.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall undertake the consideration, and make the determination, referred to in section 111 with respect to each standard established by section 111(d) in the first rate proceeding commenced after the date 3 years after the date of enactment of this Act respecting the rates of such utility if such State regulatory authority or nonregulated electric utility has not, before such date, complied with subsection (b)(2) with respect to such standard.

SEC. 113. ADOPTION OF CERTAIN STANDARDS.

(a) ADOPTION OF STANDARDS.—Not later than 2 years after the date of the enactment of this Act, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall provide public notice and conduct a hearing respecting the standards established by subsection (b) and, on the basis of such hearing, shall—

(1) adopt the standards established by subsection (b) (other than paragraph (4) thereof) if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate to carry out the purposes of this title, is otherwise appropriate, and is consistent with otherwise applicable State law, and

(2) adopt the standard established by subsection (b)(4) if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate and consistent with otherwise applicable State law.

For purposes of any determination under paragraphs (1) or (2) and any review of such determination in any court in accordance with section 123, the purposes of this title supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any such standard, pursuant to its authority under otherwise applicable State law.

(b) ESTABLISHMENT.—The following Federal standards are hereby established:

(1) MASTER METERING.—To the extent determined appropriate under section 115(d), master metering of electric service in the case of new buildings shall be prohibited or restricted to the extent necessary to carry out the purposes of this title.

(2) AUTOMATIC ADJUSTMENT CLAUSES.—No electric utility may increase any rate pursuant to an automatic adjustment clause unless such clause meets the requirements of section 115(e).

(3) INFORMATION TO CONSUMERS.—Each electric utility shall transmit to each of its electric consumers information regarding rate schedules in accordance with the requirements of section 115(f).

(4) PROCEDURES FOR TERMINATION OF ELECTRIC SERVICE.—No electric utility may terminate electric service to any electric consumer except pursuant to procedures described in section 115(g).

(5) ADVERTISING.—No electric utility may recover from any person other than the shareholders (or other owners) of such utility any direct or indirect expenditure by such utility for promotional or political advertising as defined in section 115(h).

(c) PROCEDURAL REQUIREMENTS.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility, within the 2-year period specified in subsection (a), shall (1) adopt, pursuant to subsection (a), each of the standards established by subsection (b) or, (2) with respect to any such standard which is not adopted, such authority or nonregulated electric utility shall state in writing that it has determined not to adopt such standard, together with the reasons for such determination. Such statement of reasons shall be available to the public.

SEC. 114. LIFELINE RATES.

(a) LOWER RATES.—No provision of this title prohibits a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or a nonregulated electric utility from fixing, approving, or allowing to go into effect a rate for essential needs (as defined by the State regulatory authority or by the nonregulated electric utility, as the case may be) of residential electric consumers which is lower than a rate under the standard referred to in section 111 (d)(1).

(b) DETERMINATION.—If any State regulated electric utility or nonregulated electric utility does not have a lower rate as described in subsection (a) in effect 2 years after the date of the enactment of this Act, the State regulatory authority having ratemaking authority with respect to such State regulated electric utility or the nonregulated electric utility, as the case may be, shall determine, after an evidentiary hearing, whether such a rate should be implemented by such utility.

(c) *Prior Proceedings.*—Section 124 shall not apply to the requirements of this section.

SEC. 115. SPECIAL RULES FOR STANDARDS.

(a) *Cost of Service.*—In undertaking the consideration and making the determination under section 111 with respect to the standard concerning cost of service established by section 111(d)(1), the costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined in on the basis of methods prescribed by the State regulatory authority (in the case of a State regulated electric utility) or by the electric utility (in the case of a nonregulated electric utility). Such methods shall to the maximum extent practicable—

(1) permit identification of differences in cost-incurrence for each such class of electric consumers, attributable to daily and seasonal time of use of service and

(2) permit identification of differences in cost-incurrence attributable to differences in customer, demand, and energy components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if—

(A) additional capacity is added to meet peak demand relative to base demand; and

(B) additional kilowatt-hours of electric energy are delivered to electric consumers.

(b) *Time-of-Day Rates.*—In undertaking the consideration and making the determination required under section 111 with respect to the standard for time-of-day rates established by section 111(d)(3), a time-of-day rate charged by an electric utility for providing electric service to each class of electric consumers shall be determined to be cost-effective with respect to each such class if the long-run benefits of such rate to the electric utility and its electric consumers in the class concerned are likely to exceed the metering costs and other costs associated with the use of such rates.

(c) *Load Management Techniques.*—In undertaking the consideration and making the determination required under section 111 with respect to the standard for load management techniques established by section 111(d)(6), a load management technique shall be determined, by the State regulatory authority or nonregulated electric utility, to be cost-effective if—

(1) such technique is likely to reduce maximum kilowatt demand on the electric utility, and

(2) the long-run cost-savings to the utility of such reductions are likely to exceed the long-run costs to the utility associated with implementation of such technique.

(d) *Master Metering.*—Separate metering shall be determined appropriate for any new building for purposes of section 113(b)(1) if—

(1) there is more than one unit in such building,

(2) the occupant of each such unit has control over a portion of the electric energy used in such unit, and

(3) with respect to such portion of electric energy used in such unit, the long-run benefits to the electric consumers in such building exceed the costs of purchasing and installing separate meters in such building.

(e) *Automatic Adjustment Clauses.*—(1) An automatic adjustment clause of an electric utility meets the requirements of this subsection if—

(A) such clause is determined, not less often than every 4 years, by the State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by the electric utility (in the case of a nonregulated electric utility), after an evidentiary hearing, to provide incentives for efficient use of resources (including incentives for economical purchase and use of fuel and electric energy) by such electric utility, and

(B) such clause is reviewed not less often than every 2 years, in the manner described in paragraph (2), by the State regulatory authority having ratemaking authority with respect to such utility (or by the electric utility in the case of a nonregulated electric utility), to insure the maximum economies in those operations and purchases which affect the rates to which such clasue applies.

(2) In making a review under subparagraph (B) of paragraph (1) with respect to an electric utility, the reviewing authority shall examine and, if appropriate, cause to be audited the practices of such electric utility relating to costs subject to an automatic adjustment clause, and shall require such reports as may be necessary to carry out such review (including a disclosure of any ownership or corporate relationship between such electric utility and the seller to such utility of fuel, electric energy, or other items).

(3) As used in this subsection and section 113(b), the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include an interim rate which takes effect subject to a later determination of the appropriate amount of the rate.

(f) *Information to Consumers.*—(1) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility shall transmit to each of its electric consumers a clear and concise explanation of the existing rate schedule and any rate schedule applied for (or proposed by a nonregulated electric utility) applicable to such consumer. Such statement shall be transmitted to each such consumer—

(A) not later than 60 days after the date of commencement of service to such consumer or 90 days after the standard established by section 113(b)(3) is adopted with respect to such electric utility, whichever last occurs, and

(B) not later than 30 days (60 days in the case of an electric utility which uses a bimonthly billing system) after such utility's application for any change in a rate schedule applicable to such *consumer (or proposal of such a change in the case of a nonregulated utility).*

(2) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility shall transmit to each of its electric consumers not less frequently than once each year—

(A) a clear and concise summary of the existing rate schedules applicable to each of the major classes of its electric consumers for which there is a separate rate, and

(B) an identification of any classes whose rates are not summarized.

Such summary may be transmitted together with such consumer's billing or in such other manner as the State regulatory authority or nonregulated electric utility deems appropriate.

(3) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility, on request of an electric consumer of such utility, shall transmit to such consumer a clear and concise statement of the actual consumption (or degree-day adjusted consumption) of electric energy by such consumer for each billing period during the prior year (unless such consumption data is not reasonably ascertainable by the utility).

(g) PROCEDURES FOR TERMINATION OF ELECTRIC SERVICE.—The procedures for termination of service referred to in section 113(b)(4) are procedures prescribed by the State regulatory authority (with respect to electric utilities for which it has ratemaking authority) or by the nonregulated electric utility which provide that—

(1) no electric service to an electric consumer may be terminated unless reasonable prior notice (including notice of rights and remedies) is given to such consumer and such consumer has a reasonable opportunity to dispute the reasons for such termination, and

(2) during any period when termination of service to an electric consumer would be especially dangerous to health, as determined by the State regulatory authority (with respect to an electric utility for which it was ratemaking authority) or nonregulated electric utility, and such consumer establishes that—

(A) he is unable to pay for such service in accordance with the requirments of the utility's billing, or

(B) he is able to pay for such service but only in installments,

such service may not be terminated.

Such procedures shall take into account the need to include reasonable provisions for elderly and handicapped consumers.

(h) ADVERTISING.—(1) For the purposes of this section and section 113(b)(5)—

(A) The term "advertising" means the commercial use, by an electric utility, of any media, including newspaper, printed matter, radio, and television, in order to transmit a message to a substantial number of members of the public or to such utility's electric consumers.

(B) The term "political advertising" means any advertising for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matters, or with respect to any controversial issue of public importance.

(C) The term "promotional advertising" means any advertising for the purpose of encouraging any person to select or use the service or additional service of an electric utility or the selection or installation of any appliance or equipment designed to use such utility's service.

(2) For purposes of this subsection and section 113(b)(5), the terms "political advertising" and "promotional advertising" do not include—

(A) advertising which informs electric consumers how they can conserve energy or can reduce peak demand for electric energy,

(B) advertising required by law or regulation, including advertising required under part 1 of title II of the National Energy Conservation Policy Act,

(C) advertising regarding service interruptions, safety measures, or emergency conditions,

(D) advertising concerning employment opportunities with such utility,

(E) advertising which promotes the use of energy efficient appliances, equipment or services, or

(F) any explanation or justification of existing or proposed rate schedules, or notifications of hearings thereon.

SEC. 116. REPORTS RESPECTING STANDARDS.

(a) STATE AUTHORITIES AND NONREGULATED UTILITIES.—Not later than 1 year after the date of the enactment of this Act and annually thereafter for 10 years, each State regulatory authority (with respect to each State regulated electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall report to the Secretary, in such manner as the Secretary shall prescribe, respecting its consideration of the standards established by sections 111(d) and 113(b). Such report shall include a summary of the determinations made and actions taken with respect to each such standard on a utility-by-utility basis.

(b) SECRETARY.—Not later than 18 months after the date of the enactment of this Act and annually thereafter for 10 years, the Secretary shall submit a report to the President and the Congress containing—

(1) a summary of the reports submitted under subsection (a),

(2) his analysis of such reports, and

(3) his actions under this title, and his recommendations for such further Federal actions, including any legislation, regarding retail electric utility rates (and other practices) as may be necessary to carry out the purposes of this title.

SEC. 117. RELATIONSHIP TO STATE LAW.

(a) REVENUE AND RATE OF RETURN.—Nothing in this title shall authorize or require the recovery by an electric utility of revenues, or of a rate of return, in excess of, or less than, the amount of revenues or the rate of return determined to be lawful under any other provision of law.

(b) STATE AUTHORITY.—Nothing in this title prohibits any State regulatory authority or nonregulated electric utility from adopting, pursuant to State law, any standard or rule affecting electric utilities which is different from any standard established by this subtitle.

(c) *Federal Agencies.—With respect to any electric utility which is a Federal agency, and with respect to the Tennessee Valley Authority when it is treated as a State regulatory authority as provided in section 3(17), any reference in section 111 or 113 to State law shall be treated as a reference to Federal law.*

Subtitle C—Intervention and Judicial Review

SEC. 121. INTERVENTION IN PROCEEDINGS.

(a) *Authority To Intervene and Participate.—In order to initiate and participate in the consideration of one or more of the standards established by subtitle B or other concepts which contribute to the achievement of the purposes of this title, the Secretary, any affected electric utility, or any electric consumer of an affected electric utility may intervene and participate as a matter of right in any ratemaking proceeding or other appropriate regulatory proceeding relating to rates or rate design which is conducted by a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by a nonregulated electric utility.*

(b) *Access to Information.—Any intervenor or participant in a proceeding described in subsection (a) shall have access to information available to other parties to the proceeding if such information is relevant to the issues to which his intervention or participation in such proceeding relates. Such information may be obtained through reasonable rules relating to discovery of information prescribed by the State regulatory authority (in the case of proceedings concerning electric utilities for which it has ratemaking authority) or by the nonregulated electric utility (in the case of a proceeding conducted by a nonregulated electric utility).*

(c) *Effective Date; Procedures.—Any intervention or participation under this section, in any proceeding commenced before the date of the enactment of this Act but not completed before such date, shall be permitted under this section only to the extent such intervention or participation is timely under otherwise applicable law.*

SEC. 122. CONSUMER REPRESENTATION.

(a) *Compensation for Costs of Participation or Intervention.—*
(1) If no alternative means for assuring representation of electric consumers is adopted in accordance with subsection (b) and if an electric consumer of an electric utility substantially contributed to the approval, in whole or in part, of a position advocated by such consumer in a proceeding concerning such utility, and relating to any standard set forth in subtitle B, such utility shall be liable to compensate such consumer (pursuant to paragraph (2)) for reasonable attorneys' fees, expert witness fees, and other reasonable costs incurred in preparation and advocacy of such position in such proceeding (including fees and costs of obtaining judicial review of any determination made in such proceeding with respect to such position).

(2) A consumer entitled to fees and costs under paragraph (1) may collect such fees and costs from an electric utility by bringing a civil action in any State court of competent jurisdiction, unless the State regulatory authority (in the case of a proceeding concerning a State regulated electric utility) or nonregulated electric utility (in the case of a proceeding concerning such nonregulated electric utility) has adopted a reasonable procedure pursuant to which such authority or nonregulated electric utility—

(A) determines the amount of such fees and costs, and

(B) includes an award of such fees and costs in its order in the proceeding.

(3) The procedure adopted by such State regulatory authority or nonregulated utility under paragraph (2) may include a preliminary proceeding to require that—

(A) as a condition of receiving compensation under such procedure such consumer demonstrate that, but for the ability to receive such award, participation or intervention in such proceeding may be a significant financial hardship for such consumer, and

(B) persons with the same or similar interests have a common legal representative in the proceeding as a condition to receiving compensation.

(b) *Alternative Means.—Compensation shall not be required under subsection (a) if the State, the State regulatory authority (in the case of a proceeding concerning a State regulated electric utility), or the nonregulated electric utility (in the case of a proceeding concerning such nonregulated electric utility) has provided an alternative means for providing adequate compensation to persons—*

(1) who have, or represent, an interest—

(A) which would not otherwise be adequately represented in the proceeding, and

(B) representation of which is necessary for a fair determination in the proceeding, and

(2) who are, or represent an interest which is, unable to effectively participate or intervene in the proceeding because such persons cannot afford to pay reasonable attorneys' fees, except witness fees, and other reasonable costs of preparing for, and participating or intervening in, such proceeding (including fees and costs of obtaining judicial review of such proceeding).

(c) *Transcripts.—The State regulatory authority or nonregulated electric utility, as the case may be, shall make transcripts of the proceeding available, at cost of reproduction, to parties or intervenors in any ratemaking proceeding, or other regulatory proceeding relating to rates or rate design, before a State regulatory authority or nonregulated electric utility.*

(d) *Federal Agencies.—Any claim under this section against any Federal agency shall be subject to the availability of appropriated funds.*

(e) *Rights Under Other Authority.—Nothing in this section affects or restricts any rights of any participant or intervenor in any proceeding under any other applicable law or rule of law.*

SEC. 123. JUDICIAL REVIEW AND ENFORCEMENT.

(a) *Limitation of Federal Jurisdiction.—Notwithstanding any other provision of law, no court of the United States shall have jurisdiction over any action arising under any provision of subtitle A or B or of this subtitle except for—*

(1) an action over which a court of the United States has jurisdiction under subsection (b) or (c)(2); and

(2) review of any action in the Supreme Court of the United States in accordance with sections 1257 and 1258 of title 28 of the United States Code.

(b) ENFORCEMENT OF INTERVENTION RIGHT.—(1) The Secretary may bring an action in any appropriate court of the United States to enforce his right to intervene and participate under section 121(a), and such court shall have jurisdiction to grant appropriate relief.

(2) If any electric utility or electric consumer having a right to intervene under section 121(a) is denied such right by any State court, such electric utility or electric consumer may bring an action in the appropriate United States district court to require the State regulatory authority or nonregulated electric utility to permit such intervention and participation, and such court shall have jurisdiction to grant appropriate relief.

(3) Nothing in this subsection prohibits any person bringing any action under this subsection in a court of the United States from seeking review and enforcement at any time in any State court of any rights he may have with respect to any motion to intervene or participate in any proceeding.

(c) REVIEW AND ENFORCEMENT.—(1) Any person (including the Secretary) may obtain review of any determination made under subtitle A or B or under this subtitle with respect to any electric utility (other than a utility which is a Federal agency) in the appropriate State court if such person (or the Secretary) intervened or otherwise participated in the original proceeding or if State law otherwise permits such review. Any person (including the Secretary) may bring an action to enforce the requirements of this title in the appropriate State court, except that no such action may be brought in a State court with respect to a utility which is a Federal agency. Such review or action in a State court shall be pursuant to any applicable State procedures.

(2) Any person (including the Secretary) may obtain review in the appropriate court of the United States of any determination made under subtitle A or B or this subtitle by a Federal agency if such person (or the Secretray) intervened or otherwise participated in the original proceeding or if otherwise applicable law permits such review. Such court shall have jurisdiction to grant appropriate relief. Any person (including the Secretary) may bring an action to enforce the requirements of subtitle A or B or this subtitle with respect to any Federal agency in the appropriate court of the United States and such court shall have jurisdiction to grant appropriate relief.

(3) In addition to his authority to obtain review under paragraph (1) or (2), the Secretary may also participate as an amicus curiae in any review by any court of an action arising under the provisions of subtitle A or B or this subtitle.

(d) OTHER AUTHORITY OF THE SECRETARY.—Nothing in this section prohibits the Secretary from—

(1) intervening and participating in any proceeding, or

(2) intervening and participating in any review by any court of any action

under section 204 of the Energy Conservation and Production Act.

SEC. 124. PRIOR AND PENDING PROCEEDINGS.

For purposes of subtitles A and B, and this subtitle, proceedings commenced by State regulatory authorities (with respect to electric utilities for which it has ratemaking authority) and nonregulated electric utilities before the date of the enactment of this Act and actions taken before such date in such proceedings shall be treated as complying with the requirements of subtitles A and B, and this subtitle if such proceedings and actions substantially conform to such requirements. For purposes of subtitles A and B, and this subtitle, any such proceeding or action commenced before the date of enactment of this Act, but not completed before such date, shall comply with the requirements of subtitles A and B, and this subtitle, to the maximum extent practicable, with respect to so much of such proceeding or action as takes place after such date, except as otherwise provided in section 121(c).

Subtitle D—Administrative Provisions

SEC. 131. VOLUNTARY GUIDELINES.

The Secretary may prescribe voluntary guidelines respecting the standards established by sections 111(d) and 113(b). Such guidelines may not expand the scope or legal effect of such standards or establish additional standards respecting electric utility rates.

SEC. 132. RESPONSIBILITIES OF SECRETARY OF ENERGY.

(a) AUTHORITY.—The Secretary may periodically notify the State regulatory authorities, and electric utilities identified pursuant to section 102(c), of—

(1) load management techniques and the results of studies and experiments concerning load management techniques;

(2) developments and innovations in electric utility ratemaking throughout the United States, including the results of studies and experiments in rate structure and rate reform;

(3) methods for determining cost of service; and

(4) any other data or information which the Secretary determines would assist such authorities and utilities in carrying out the provisions of this title.

(b) TECHNICAL ASSISTANCE.—The Secretary may provide such technical assistance as he determines appropriate to assist the State regulatory authorities in carrying out their responsibilities under subtitle B and as is requested by any State regulatory authority relating to the standards established by subtitle B.

(c) APPROPRIATIONS.—There are authorized to be appropriated to carry out the purposes of subsection (b) not to exceed $1,000,000 for each of the fiscal years 1979 and 1980.

SEC. 133. GATHERING INFORMATION ON COSTS OF SERVICE.

(a) INFORMATION REQUIRED TO BE GATHERED.—Each electric utility shall periodically gather information under such rules (promulgated by the Commission) as the Commission determines necessary to allow determination of the costs associated with providing electric service. For purposes of this section, and for purposes of any consideration and determination respecting the standard established by section 111(d)(2), such costs shall be separated, to the maximum extent practicable, into the following components: customer cost component, demand cost component, and energy cost component. Rules under this subsection shall include requirements for the gathering of the following information with respect to each electric utility—

(1) the costs of serving each electric consumer class, including costs of serving different consumption patterns within such class, based on voltage level, time of use, and other appropriate factors;

(2) daily kilowatt demand load curves for all electric consumer classes combined representative of daily and seasonal differences in demand, and daily kilowatt demand load curves for each electric consumer class for which there is a separate rate, representative of daily and seasonal differences in demand;

(3) annual capital, operating, and maintenance costs—

(A) for transmission and distribution services, and

(B) for each type of generating unit; and

(4) costs of purchased power, including representative daily and seasonal differences in the amount of such costs.

Such rules shall provide that information required to be gathered under this section shall be presented in such categories and such detail as may be necessary to carry out the purposes of this section.

(b) COMMISSION RULES.—The Commission shall, within 180 days after the date of enactment of this Act, by rule, prescribe the methods, procedure, and format to be used by electric utilities in gathering the information described in this section. Such rules may provide for the exemption by the Commission of an electric utility or class of electric utilities from gathering all or part of such information, in cases where such utility or utilities show and the Commission finds, after public notice and opportunity for the presentation of written data, views, and arguments, that gathering such information is not likely to carry out the purposes of this section. The Commission shall periodically review such findings and may revise such rules.

(c) FILING AND PUBLICATION.—Not later than 2 years after the date of enactment of this Act, and periodically, but not less frequently than every 2 years thereafter, each electric utility shall file with—

(1) the Commission, and

(2) any State regulatory authority which has ratemaking authority for such utility,

the information gathered pursuant to this section and make such information available to the public in such form and manner as the Commission shall prescribe. In addition, at the time of application for, or proposal of, any rate increase, each electric utility shall make such information available to the public in such form and manner as the Commission shall prescribe. The 2-year period after the date of the enactment specified in this subsection may be extended by the Commission for a reasonable additional period in the case of any electric utility for good cause shown.

(d) ENFORCEMENT.—For purposes of enforcement, any violation of a requirement of this section shall be treated as a violation of a provision of the Energy Supply and Environmental Coordination Act of 1974 enforceable under section 12 of such Act (notwithstanding any expiration date in such Act) except that in applying the provisions of such section 12 any reference to the Federal Energy Administrator shall be treated as a reference to the Commission.

SEC. 134. RELATIONSHIP TO OTHER AUTHORITY.

Nothing in this title shall be construed to limit or affect any authority of the Secretary or the Commission under any other provision of law.

Subtitle E—State Utility Regulatory Assistance

SEC. 141. GRANTS TO CARRY OUT TITLES I AND III.

Section 207 of title II of the Energy Conservation and Production Act is amended to read as follows:

"STATE UTILITY REGULATORY ASSISTANCE

"SEC. 207. (a) The Secretary may make grants to State utility regulatory commissions and nonregulated electric utilities (as defined in the Public Utility Regulatory Policies Act of 1978) to carry out duties and responsibilities under titles I and III, and section 210, of the Public Utility Regulatory Policies Act of 1978. No grant may be made under this section to any Federal agency.

"(b) Any requirements established by the Secretary with respect to grants under this section may be only such requirements as are necessary to assure that such grants are expended solely to carry out duties and responsibilities referred to in subsection (a) or such as are otherwise required by law.

"(c) No grant may be made under this section unless an application for such grant is submitted to the Secretary in such form and manner as the Secretary may require. The Secretary may not approve an application of a State utility regulatory commission or nonregulated electric utility unless such commission or nonregulated electric utility assures the Secretary that funds made available under this section will be in addition to, and not in substitution for, funds made available to such commission or nonregulated electric utility from other governmental sources.

"(d) The funds appropriated for purposes of this section shall be apportioned among the States in such manner that grants made under this section in each State shall not exceed the lesser of—

"(1) the amount determined by dividing equally among all States the total amount available under this section for such grants, or

"(2) the amount which the Secretary is authorized to provide pursuant to subsections (b) and (c) of this section for such State".

SEC. 142. AUTHORIZATIONS.

Title II of the Energy Conservation and Production Act is amended by adding the following at the end thereof:

"AUTHORIZATION OF APPROPRIATIONS

"SEC. 208. There are authorized to be appropriated—

"(1) not to exceed $40,000,000 for each of the fiscal years 1979 and 1980 to carry out section 207 (relating to State utility regulatory assistance);

"(2) not to exceed $10,000,000 for each of the fiscal years 1979 and 1980 to carry out section 205 (relating to State offices of consumer services); and

"(3) not to exceed $8,000,000 for the fiscal year 1979, and $10,000,000 for the fiscal year 1980 to carry out section 204(1)(B) (relating to innovative rate structures)."

SEC. 113. CONFORMING AMENDMENTS.

Title II of the Energy Conservation and Production Act is amended by striking out "Administrator" in each place it appears and substituting "Secretary".

(b) Definition.—Section 202(1) of the Energy Conservation and Production Act is amended to read as follows:

"(1) The term 'Secretary' means the Secretary of Energy.".

TITLE II—CERTAIN FEDERAL ENERGY REGULATORY COMMISSION AND DEPARTMENT OF ENERGY AUTHORITIES

SEC. 201. DEFINITIONS.

Section 3 of the Federal Power Act is amended by inserting the following before th period at the end thereof:

"(17)(A) 'small power production facility' means a facility which—

"(i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof; and

"(ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts;

"(B) 'primary energy source' means the fuel or fuels used for the generation of electric energy, except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy—

"(i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and

"(ii) the minimum amounts of fuel required to alleviate or prevent—

"(I) unanticipated equipment outages, and

"(II) emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages;

"(C) 'qualifying small power production facility' means a small power production facility—

"(i) which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe; and

"(ii) which is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

"(D) 'qualifying small power producer' means the owner or operator of a qualifying small power production facility;

"(18)(A) 'cogeneration facility' means a facility which produces—

"(i) electric energy, and

"(ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes;

"(B) 'qualifying cogeneration facility' means a cogeneration facility which—

"(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe; and

"(ii) is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

"(C) 'qualifying cogenerator' means the owner or operator of a qualifying cogeneratioin facility;

"(19) 'Federal power marketing agency' means any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy;

"(20) 'evidentiary hearing' and 'evidentiary proceeding' mean a proceeding conducted as provided in sections 554, 556, and 557 of title 5, United States Code;

"(21) 'State regulatory authority' has the same meaning as the term 'State commission', except that in thecase of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority (as defined in section 3 of the Public Utility Regulatory Policies Act of 1978), such term means the Tennessee Valley Authority;

"(22) 'electric utility' means any person or State agency which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency".

SEC. 202. INTERCONNECTION.

Part II of the Federal Power Act is amended by adding the following new section at the end thereof:

"CERTAIN INTERCONNECTION AUTHORITY

"SEC. 210. (a)(1) Upon application of any electric utility, Federal power marketing agency, qualifying cogenerator, or qualifying small power producer, the Commission may issue an order requiring—

"(A) the physical connection of any cogeneration facility, any small power production facility, or the transmission facilities of any electric utility, with the facilities of such applicant,

"(B) such action as may be necessary to make effective any physical connection described in subparagraph (A), which physical connection is ineffective for any reason, such as inadequate size, poor maintenance, or physical unreliability,

"(C) such sale or exchange of electric energy, or other coordination, as may be necessary to carry out the purposes of any order under subparagraph (A) or (B), or

"(D) such increase in transmission capacity as may be necessary to carry out the purposes of any order under subparagraph (A) or (B).

"(2) Any State regulatory authority may apply to the Commission for an order for any action referred to in subparagraph (A), (B), (C),

or (D) of paragraph (1). No such order may be issued by the Commission with respect to a Federal power marketing agency upon application of a State regulatory authority.

"(b) Upon receipt of an application under subsection (a), the Commission shall—

"(1) issue notice to each affected State regulatory authority, each affected electric utility, each affected Federal power marketing agency, each affected owner or operator of a cogeneration facility or of a small power production facility, and to the public.

"(2) afford an opportunity for an evidentiary hearing, and

"(3) make a determination with respect to the matters referred to in subsection (c).

"(c) No order may be issued by the Commission under subsection (a) unless the Commission determines that such order—

"(1) is in the public interest,

"(2) would—

"(A) encourage overall conservation of energy or capital,

"(B) optimize the efficiency of use of facilities and resources, or

"(C) improve the reliability of any electric utility system or Federal power marketing agency to which the order applies, and

"(3) meets the requirements of section 212.

"(d) The Commission may, on its own motion, after compliance with the requirements of paragraphs (1) and (2) of subsection (b), issue an order requiring any action described in subsection (a)(1) if the Commission determines that such order meets the requirements of subsection (c). No such order may be issued upon the Commission's own motion with respect to a Federal power marketing agency.

"(e)(1) As used in this section, the term 'facilities' means only facilities used for the generation or transmission of electric energy.

"(2) With respect to an order issued pursuant to an application of a qualifying cogenerator or qualifying small power producer under subsection (a)(1), the term 'facilities of such applicant' means the qualifying cogeneration facilities or qualifying small power production facilities of the applicant, as specified in the application. With respect to an order issued pursuant to an application under subsection (a)(2), the term 'facilities of such applicant" means the qualifying cogeneration facilities, qualifying small power production facilities, or the transmission facilities of an electric utility, as specified in the application. With respect to an order issued by the Commission on its own motion under subsection (d), such term means the qualifying cogeneration facilities, qualifying small power production facilities, or the transmission facilities of an electric utility, as specified in the proposed order.".

SEC. 203. WHEELING.

Part II of the Federal Power Act, as amended by section 202 of this Act, is further amended by adding the following new section at the end thereof:

"CERTAIN WHEELING AUTHORITY

"SEC. 211. (a) Any electric utility or Federal power marketing agency may apply to the Commission for an order under this subsection requiring any other electric utility to provide transmission services to the applicant

(including any enlargement of transmission capacity necessary to provide such services). Upon receipt of such application, after public notice and notice to each affected State regulatory authority, each affected electric utility, and each affected Federal power marketing agency, and after affording an opportunity for an evidentiary hearing, the Commission may issue such order if it finds that such order—

"(1) is in the public interest,

"(2) would—

"(A) conserve a significant amount of energy,

"(B) significantly promote the efficient use of facilities and resources, or

"(C) improve the reliability of any electric utility system to which the order applies, and

"(3) meets the requirements of section 212.

"(b) Any electric utility, or Federal power marketing agency, which purchases electric energy for resale from any other electric utility may apply to the Commission for an order under this subsection requiring such other electric utility to provide transmission services to the applicant (including any increase in transmission capacity necessary to provide such services). Upon receipt of an application under this subsection, after public notice and notice to each affected State regulatory authority, each affected electric utility, and each affected Federal power marketing agency, and after affording an opportunity for an evidentiary hearing, the Commission may issue such an order if the Commission determines that—

"(1) such other electric utility has given actual or constructive notice that it is unwilling or unable to provide electric service to the applicant and has been requested by the applicant to provide the transmission services requested in the application under this subsection, and

"(2) such order meets the requirements of section 212.

"(c)(1) No order may be issued under subsection (a) unless the Commission determines that such order would reasonably preserve existing competitive relationships.

"(2) No order may be issued under subsection (a) or (b) which requires the electric utility subject to the order to transmit, during any period, an amount of electric energy which replaces any amount of electric energy—

"(A) required to be provided to such applicant pursuant to a contract during such period, or

"(B) currently provided to the applicant by the utility subject to the order pursuant to a rate schedule on file during such period with the Commission.

"(3) No order may be issued under the authority of subsection (a) or (b) which is inconsistent with any State law which governs the retail marketing areas of electric utilities.

"(4) No order may be issued under subsection (a) or (b) which provides for the transmission of electric energy directly to an ultimate consumer.

"(d)(1) Any electric utility ordered under subsection (a) or (b) to provide transmission services may apply to the Commission for an order permitting such electric utility to cease providing all, or any portion of, such services. After public notice, notice to each affected

State regulatory authority, each affected Federal power marketing agency, and each affected electric utility, and after an opportunity for an evidentiary hearing, the Commission shall issue an order terminating or modifying the order issued under subsection (a) or (b), if the electric utility providing such transmission services has demonstrated, and the Commission has found, that—

"(A) due to changed circumstances, the requirements applicable, under this section and section 212, to the issuance of an order under subsection (a) or (b) are no longer met, or

"(B) any transmission capacity of the utility providing transmission services under such order which was, at the time such order was issued, in excess of the capacity necessary to serve its own customers is no longer in excess of the capacity necessary for such purposes.

No order shall be issued under this subsection pursuant to a finding under subparagraph (A) unless the Commission finds that such order is in the public interest.

"(2) Any order issued under this subsection terminating or modifying an order issued under subsection (a) or (b) shall—

"(A) provide for any appropriate compensation, and

"(B) provide the affected electric utilities adequate opportunity and time to—

(i) make suitable alternative arrangements for any transmission services terminated or modified, and

(ii) insure that the interests of taxpayers of such utilities are adequately protected.

"(3) No order may be issued under this subsection terminating or modifying any order issued under subsection (a) or (b) if the order under subsection (a) or (b) includes terms and conditions agreed upon by the parties which—

"(A) fix a period during which transmission services are to be provided under the order under subsection (a) or (b), or

"(B) otherwise provide procedures or methods for terminating or modifying such order (including, if appropriate, the return of the transmission capacity when necessary to take into account an increase, after the issuance of such order, in the needs of the electric utility subject to such order for transmission capacity).

"(e) As used in this section, the term "facilities" means only facilities used for the generation or transmission of electric energy.".

SEC. 204. GENERAL PROVISIONS REGARDING CERTAIN INTERCONNECTION AND WHEELING AUTHORITY.

(a) Restrictions and Other Provisions.—Part II of the Federal Power Act, as amended by sections 202 and 203 of this Act, is further amended by adding the following new section at the end thereof:

"PROVISIONS REGARDING CERTAIN ORDERS REQUIRING INTERCONNECTION OR WHEELING

"Sec. 212. (a) No order may be issued by the Commission under section 210 or subsection (a) or (b) of section 211 unless the Commission determines that such order—

"(1) is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility, qualifying cogenerator, or qualifying small power producer, as the case may be, affected by the order;

"(2) will not place an undue burden on an electric utility, qualifying cogenerator, or qualifying small power producer, as the case may be, affected by the order;

"(3) will not unreasonably impair the reliability of any electric utility affected by the order; and

"(4) will not impair the ability of any electric utility affected by the order to render adequate service to its customers.

The determination under paragraph (1) shall be based upon a showing of the parties. The Commission shall have no authority under section 210 or 211 to compel the enlargement of generating facilities.

"(b) No order may be issued under section 210 or subsection (a) or (b) or section 211 unless the applicant for such order demonstrates that he is ready, willing, and able to reimburse the party subject to such order for—

"(1) in the case of an order under section 210, such party's share of the reasonably anticipated costs incurred under such order, and

"(2) in the case of an order under subsection (a) or (b) of section 211—

"(A) the reasonable costs of transmission services, including the costs of any enlargement of transmission facilities, and

"(B) a reasonable rate of return on such costs, as appropriate, as determined by the Commission.

"(c)(1) Before issuing an order under section 210 or subsection (a) or (b) of section 211, the Commission shall issue a proposed order and set a reasonable time for parties to the proposed interconnection or transmission order to agree to terms and conditions under which such order is to be carried out, including the apportionment of costs between them and the compensation or reimbursement reasonably due to any of them. Such proposed order shall not be reviewable or enforceable in any court. The time set for such parties to agree to such terms and conditions may be shortened if the Commission determines that delay would jeopardize the attainment of the purposes of any proposed order. Any terms and conditions agreed to by the parties shall be subject to the approval of the Commission.

"(2)(A) If the parties agree as provided in paragraph (1) within the time set by the Commission and the Commission approves such agreement, the terms and conditions shall be included in the final order. In the case of an order under section 210, if the parties fail to agree within the time set by the Commission or if the Commission does not approve any such agreement, the Commission shall prescribe such terms and conditions and include such terms and conditions in the final order.

"(B) In the case of any order applied for under section 211, if the parties fail to agree within the time set by the Commission, the Commission shall prescribe such terms and conditions in the final order.

"(d) If the Commission does not issue any order applied for under section 210 or 211, the Commission shall, by order, deny such application and state the reasons for such denial.

"(e) No provision of section 210 or 211 shall be treated—

"(1) as requiring any person to utilize the authority of such section 210 or 211 in lieu of any other authority of law, or

"(2) as limiting, impairing, or otherwise affecting any authority of the Commission under any other provision of law.

"(f)(1) No order under section 210 or 211 requiring the Tennessee Valley Authority (hereinafter in this section referred to as the 'TVA') to take any action shall take effect for 60 days following the date of issuance of the order. Within 60 days following the issuance by the Commission of any order under section 210 or of section 211 requiring the TVA to enter into any contract for the sale or delivery of power, the Commission may on its own motion initiate, or upon petition of any aggrieved person shall initiate, an evidentiary hearing to determine whether or not such sale or delivery would result in violation of the third sentence of section 15d(a) of the Tennessee Valley Authority Act of 1933 (16 U.S.C. 831n–4), hereinafter in this subsection referred to at the TVA Act.

"(2) Upon initiation of any evidentiary hearing under paragraph (1), the Commission shall give notice thereof to any applicant who applied for and obtained the order from the Commission, to any electric utility or other entity subject to such order, and to the public, and shall promptly make the determination referred to in paragraph (1). Upon initiation of such hearing, the Commission shall stay the effectiveness of the order under section 210 or 211 until whichever of the following dates is applicable—

"(A) the date on which there is a final determination (including any judicial review thereof under paragraph (3)) that no such violation would result from such order, or

"(B) the date on which a specific authorization of the Congress (within the meaning of the third sentence of section 15(a) of the TVA Act) takes effect.

"(3) Any determination under paragraph (1) shall be reviewable only in the appropriate court of the United States upon petition filed by any aggrieved person or municipality within 60 days after such determination, and such court shall have jurisdiction to grant appropriate relief. Any applicant who applied for and obtained the order under section 210 or 211, and any electric utility or other entity subject to such order shall have the right to intervene in any such proceeding in such court. Except for review by such court (and any appeal or other review by an appellate court of the United States), no court shall have jurisdiction to consider any action brought by any person to enjoin the carrying out of any order of the Commission under section 210 or section 211 requiring the TVA to take any action on the grounds that such action requires a specific authorization of the Congress pursuant to the third sentence of section 15d(a) of the TVA Act.".

(b) APPLICATION OF FEDERAL POWER ACT.—(1) Section 201(b) of such Act is amended by inserting "(1)" after "(b)", by inserting "except as provided in paragraph (2)" after "but" in the first sentence thereof, and by adding the following at the end thereof:

"(2) The provisions of sections 210, 211, and 212 shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this Act with respect to such provisions. Compliance with any order of the Commission under the provisions of section 210 or 211, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.".

(2) Section 201(e) of such Act is amended by inserting "(other than facilities subject to such jurisdiction solely by reason of section 210, 211, or 212)" after "under this part".

SEC. 205. POOLING.

(a) STATE LAWS.—The Commission may, on its own motion, and shall, on application of any person or governmental entity, after public notice and notice to the Governor of the affected State and after affording an opportunity for public hearing, exempt electric utilities, in whole or in part, from any provision of State law, or from any State rule or regulation, which prohibits or prevents the voluntary coordination of electric utilities, including any agreement for central dispatch, if the Commission determines that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area. No such exemption may be granted if the Commission finds that such provision of State law, or rule or regulation—

(1) is required by any authority of Federal law, or

(2) is designed to protect public health, safety, or welfare, or the environment or conserve energy or is designed to mitigate the effects of emergencies resulting from fuel shortages.

(b) POOLING STUDY.—(1) The Commission, in consultation with the reliability councils established under section 202(a) of the Federal Power Act, the Secretary, and the electric utility industry shall study the opportunities for—

(A) conservation of energy,

(B) optimization in the efficiency of use of facilities and resources, and

(C) increased reliability,

through pooling arrangements. Not later than 18 months after the date of the enactment of this Act, the Commission shall submit a report containing the results of such study to the President and the Congress.

(2) The Commission may recommend to electric utilities that such utilities should voluntarily enter into negotiations where the opportunities referred to in paragraph (1) exist. The Commission shall report annually to the President and the Congress regarding any such recommendations and subsequent actions taken by electric utilities, by the Commission, and by the Secretary under this Act, the Federal Power Act, and any other provision of law. Such annual reports shall be included in the Commission's annual report required under the Department of Energy Organization Act.

SEC. 206. CONTINUANCE OF SERVICE.

(a) AMENDMENT OF FEDERAL POWER ACT.—Section 202 of the Federal Power Act is amended by adding the following new subsection at the end thereof:

"(g) In order to insure continuity of service to customers of public utilities, the Commission shall require, by rule, each public utility to—

"(1) report promptly to the Commission and any appropriate State regulatory authorities any anticipated shortage of electric energy or capacity which would affect such utility's capability of serving its wholesale customers, "(2) submit to the Commission and to any appropriate State regulatory authority, and periodically revise, contingency plans respecting—

"(A) shortages of electric energy or capacity, and

"(B) circumstances which may result in such shortages, and

"(3) accommodate any such shortages or circumstances in a manner which shall—

"(A) give due consideration to the public health, safety, and welfare, and

"(B) provide that all persons served directly or indirectly by such public utility will be treated, without undue prejudice or disadvantage.".

(b) EFFECTIVE DATE.—The amendment made by subsection (a) shall not affect any proceeding of the Commission pending on the date of the enactment of this Act or any case pending on such date respecting a proceeding of the Commission.

SEC. 207. CONSIDERATION OF PROPOSED RATE INCREASES.

(a) NOTICE PERIOD.—Section 205(d) of the Federal Power Act is amended by striking out "thirty" each place it appears and substituting "sixty".

(b) STUDY.—The chairman of the Federal Energy Regulatory Commission, in consultation with the Secretary is directed to conduct a study of the legal requirements and administrative procedures involved in the consideration and resolution of proposed wholesale electric rate increases under the Federal Power Act for the purposes of (1) providing for expeditious handling of hearings consistent with due process, (2) preventing the imposition of successive rate increases before they have been determined by the Commission to be just and reasonable and otherwise lawful, and (3) improving procedures designed to prohibit anticompetitive or unreasonable differences in wholesale and retail rates, or both. The chairman shall report to Congress within 9 months from the date of enactment of this Act on the results of the study required under this section, on the administrative actions taken as a result of this study, and on any recommendations for changes in existing law that will aid the purposes of this section.

SEC. 208. AUTOMATIC ADJUSTMENT CLAUSES.

Section 205 of the Federal Power Act is amended by adding the following new subsection at the end thereof:

"(f)(1) Not later than 2 years after the date of the enactment of this subsection and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

"(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

"(B) whether any such clause reflects any costs other than costs which are—

"(i) subject to periodic fluctuations and

"(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

"(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

"(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to—

"(A) modify the terms and provisions of any automatic adjustment clause, or

"(B) cease any practice in connection with the clause,

if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

"(4) As used in this subsection, the term 'automatic adjustment clause' means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.".

SEC. 209. RELIABILITY.

(a) STUDY.—(1) The Secretary, in consultation with the Commission, shall conduct a study with respect to—

(A) the level of reliability appropriate to adequately serve the needs of electric consumers, taking into account cost effectiveness and the need for energy conservation,

(B) the various methods which could be used in order to achieve such level of reliability and the cost effectiveness of such methods, and

(C) the various procedures that might be used in case of an emergency outage to minimize the public disruption and economic loss that might be caused by such an outage and the cost effectiveness of such procedures.

Such study shall be completed and submitted to the President and the Congress not later than 18 months after the date of the enactment of this Act. Before such submittal the Secretary shall provide an opportunity for public comment on the results of such study.

(2) The study under paragraph (1) shall include consideration of the following:

(A) the cost effectiveness of investments in each of the components involved in providing adequate and reliable electric service, including generation, transmission, and distribution facilities, and devices available to the electric consumer;

(B) the environmental and other effects of the investments considered under subparagraph (A);

(C) various types of electric utility systems in terms of generation, transmission, distribution and customer mix, the extent to which differences in reliability levels may be desirable, and the cost-effectiveness of the various methods which could be used to decrease the number and severity of any outages among the various types of systems;

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

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(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; and

(F) any standards for electric utility reliability used by, or suggested for use by, the electric utility industry in terms of cost-effectiveness in achieving the desired level of reliability, including equipment standards, standards for operating procedures and training of personnel, and standards relating the number and severity of outages to periods of time.

(b) EXAMINATION OF RELIABILITY ISSUES BY RELIABILITY COUNCILS.—The Secretary, in consultation with the Commission, may, from time to time, request the reliability councils established under section 202(a) of the Federal Power Act or other appropriate persons (including Federal agencies) to examine and report to him concerning any electric utility reliability issue. The Secretary shall report to the Congress (in its annual report or in the report required under subsection (a) if appropriate) the results of any examination under the preceding sentence.

(c) DEPARTMENT OF ENERGY RECOMMENDATIONS.—The Secretary, in consultation with the Commission, and after opportunity for public comment, may recommend industry standards for reliability to the electric utility industry, including standards with respect to equipment, operating procedures and training of personnel, and standards relating to the level or levels of reliability appropriate to adequately and reliably serve the needs of electric consumers. The Secretary shall include in his annual report—

(1) any recommendations made under this subsection or any recommendations respecting electric utility reliability problems under any other provision of law, and

(2) a description of actions taken by electric utilities with respect to such recommendations.

SEC. 210. COGENERATION AND SMALL POWER PRODUCTION.

(a) COGENERATION AND SMALL POWER PRODUCTION RULES.—Not later than 1 year after the date of enactment of this Act, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production which rules require electric utilities to offer to—

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) RATES FOR PURCHASES BY ELECTRIC UTILITIES.—The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) RATES FOR SALES BY UTILITIES.—The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale—

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) DEFINITION.—For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) EXEMPTIONS.—(1) Not later than 1 year after the date of enactment of this Act and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which qualifying cogeneration facilities and qualifying small power production facilities are exempted in whole or part from the Federal Power Act, from the Public Utility Holding Company Act, from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source may be exempted by the Commission under such rules from the Public Utility Holding Company Act and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—

(A) any State law or regulation in effect in a State pursuant to subsection (f), (*B*) *the provisions of section 210, 211, or 212 of the Federal Power Act or the necessary authorities for enforcement of any such provision under the Federal Power Act, or*

(*C*) *any license or permit requirement under part I of the Federal Power Act, any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.*

(*f*) *IMPLEMENTATION OF RULES FOR QUALIFYING COGENERATION AND QUALIFYING SMALL POWER PRODUCTION FACILITIES.—(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.*

SMALL QUALIFYING POWER PRODUCTION FACILITIES.—(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(*g*) *JUDICIAL REVIEW AND ENFORCEMENT.—(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) in the same manner, and under the same requirements, as judicial review may be obtained under section 123 in the case of a proceeding to which section 123 applies.*

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f). Any such action shall be brought only in the manner, and under the requirements, as provided under section 123 with respect to an action to which section 123 applies.

(*h*) *COMMISSION ENFORCEMENT.—(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act, such rule shall be treated as a rule under the Federal Power Act. Nothing in subsection (g) shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.*

(2)(A) The Commission may enforce the requirements of subsection (f) against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) shall be treated as a rule enforceable under the Federal Power Act. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than—

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(*i*) *FEDERAL CONTRACTS.—No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after the date of the enactment of this Act may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.*

(*j*) *DEFINITIONS.—For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3 (17) and (18) of the Federal Power Act.*

SEC. 211. INTERLOCKING DIRECTORATES.

(a) AMENDMENT OF FEDERAL POWER ACT.—Section 305 of the Federal Power Act is amended by adding the following new subsection at the end thereof:

"(c)(1) On or before April 30 of each year, any person who, during the calendar year preceding the filing date under this subsection, was an officer or director of a public utility and who held, during such calendar year, the position of officer, director, partner, appointee, or representative of any other entity listed in paragraph (2) shall file with the Commission, in such form and manner as the Commission shall by rule prescribe, a written statement concerning such positions held by such person. Such statement shall be available to the public.

"(2) The entities listed for purposes of paragraph (1) are as follows—

"(A) any investment bank, bank holding company, foreign bank or subsidiary thereof doing business in the United States, insurance company, or any other organization primarily engaged in the business of providing financial services or credit, a mutual savings bank, or a savings and loan association;

"(B) any company, firm, or organization which is authorized by law to underwrite or participate in the marketing of securities of a public utility;

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"(C) any company, firm, or organization which produces or supplies electrical equipment or coal, natural gas, oil, nuclear fuel, or other fuel, for the use of any public utility;

"(D) any company, firm, or organization which during any one of the 3 calendar years immediately preceding the filing date was one of the 20 purchasers of electric energy which purchased (for purposes other than for resale) one of the 20 largest annual amounts of electric energy sold by such public utility (or by any public utility which is part of the same holding company system) during any one of such three calendar years;

"(E) any entity referred to in subsection (b); and

"(F) any company, firm, or organization which is controlled by any company, firm, or organization referred to in this paragraph.

On or before January 31 of each calendar year, each public utility shall publish a list, pursuant to rules prescribed by the Commission, of the purchasers to which subparagraph (D) applies, for purposes of any filing under paragraph (1) of such calendar year.

"(3) For purposes of this subsection—

"(A) The term 'public utility' includes any company which is a part of a holding company system which includes a registered holding company, unless no company in such system is an electric utility.

"(B) The terms 'holding company', 'registered holding company', and 'holding company system' have the same meaning as when used in the Public Utility Holding Company Act of 1935.".

(b) EFFECTIVE DATE.—No person shall be required to file a statement under section 305(c)(1) of the Federal Power Act before April 30 of the second calendar year which begins after the date of the enactment of this Act and no public utility shall be required to publish a list under section 305(c)(2) of such Act before January 31 of such second calendar year.

SEC. 212. PUBLIC PARTICIPATION BEFORE FEDERAL ENERGY REGULATORY COMMISSION.

The Federal Power Act is amended by redesignating sections 319 and 320 as 320 and 321, respectively, and by inserting the following new section after section 318:

"OFFICE OF PUBLIC PARTICIPATION

"SEC. 319. (a)(1) There shall be an office in the Commission to be known as the Office of Public Participation (hereinafter in this section referred to as the 'Office').

"(2)(A) The Office shall be administered by a Director. The Director shall be appointed by the Chairman with the approval of the Commission. The Director may be removed during his term of office by the Chairman, with the approval of the Commission, only for inefficiency, neglect of duty, or malfeasance in office.

"(B) The term of office of the Director shall be 4 years. The Director shall be responsible for the discharge of the functions and duties of the Office. He shall be appointed and compensated at a rate not in excess of the maximum rate prescribed for GS-18 of the General Schedule under section 5332 of title 5 of the United States Code.

"(3) The Director may appoint, and assign the duties of, employees of such Office, and with the concurrence of the Commission he may fix the compensation of such employees and procure temporary and intermittent services to the same extent as is authorized under section 3109 of title 5, United States Code.

"(b)(1) The Director shall coordinate assistance to the public with respect to authorities exercised by the Commission. The Director shall also coordinate assistance available to persons intervening or participating or proposing to intervene or participate in proceedings before the Commission.

"(2) The Commission may, under rules promulgated by it, provide compensation for reasonable attorneys's fees, expert witness fees, and other costs of intervening or participating in any proceeding before the Commission to any person whose intervention or participation substantially contributed to the approval, in whole or in part, of a position advocated by such person. Such compensation may be paid only if the Commission has determined that—

"(A) the proceeding is significant, and

"(B) such person's intervention or participation in such proceeding without receipt of compensation constitutes a significant financial hardship to him.

"(3) Nothing in this subsection affects or restricts any rights of any intervenor or participant under any other applicable law or rule of law.

"(4) There are authorized to be appropriated to the Secretary of Energy to be used by the Office for purposes of compensation of persons under the provisions of this subsection not to exceed $500,000 for the fiscal year 1978, not to exceed $2,000,000 for the fiscal year 1979, not to exceed $2,200,000 for the fiscal year 1980, and not to exceed $2,400,000 for the fiscal year 1981.".

SEC. 213. CONDUIT HYDROELECTRIC FACILITIES

Part I of the Federal Power Act is amended by adding the following new section at the end thereof:

"SEC. 30. (a) Except as provided in subsection (b) or (c), the Commission may grant an exemption in whole or in part from the requirements of this part, including any license requirements contained in this part, to any facility (not including any dam or other impoundment) constructed, operated, or maintained for the generation of electric power which the Commission determines, by rule or order—

"(1) is located on non-Federal lands, and

"(2) utilizes for such generation only the hydroelectric potential of a manmade conduit, which is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity.

"(b) The Commission may not grant any exemption under subsection (a) to any facility the installed capacity of which exceeds 15 megawatts.

"(c) In making the determination under subsection (a) the Commission shall consult with the United States Fish and Wildlife Service and the State agency exercising administration over the fish and wildlife resources of the State in which the facility is or will be located, in the manner provided by the Fish and Wildlife Coordination Act (16 U.S.C. 661, et seq.), and shall include in any such exemption—

"(1) such terms and conditions as the Fish and Wildlife Service and the State agency each determine are appropriate to prevent loss of, or damage to, such resources and to otherwise carry out the purposes of such Act, and

"(2) such terms and conditions as the Commission deems appropriate to insure that such facility continues to comply with the provisions of this section and the terms and conditions included in any such exemption.

"(d) Any violation of a term or condition of any exemption granted under subsection (a) shall be treated as a violation of a rule or order of the Commission under this Act.".

SEC. 214. PRIOR ACTION; EFFECT ON OTHER AUTHORITIES.

(a) PRIOR ACTIONS.—No provision of this title or of any amendment made by this title shall apply to, or affect, any action taken by the Commission before the date of the enactment of this Act.

(b) OTHER AUTHORITIES.—No provision of this title or of any amendment made by this title shall limit, impair or otherwise affect any authority of the Commission or any other agency or instrumentality of the United States under any other provision of law except as specifically provided in this title.

TITLE III—RETAIL POLICIES FOR NATURAL GAS UTILITIES

SEC. 301. PURPOSES; COVERAGE.

(a) PURPOSES.—The purposes of this title are to encourage—

(1) conservation of energy supplied by gas utilities;

(2) the optimization of the efficiency of use of facilities and resources by gas utility systems; and

(3) equitable rates to gas consumers of natural gas.

(b) VOLUME OF TOTAL RETAIL SALES.—This title applies to each gas utility in any calendar year, and to each proceeding relating to each gas utility in such year, if the total sales of natural gas by such utility for purposes other than resale exceeded 10 billion cubic feet during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(c) EXCLUSION OF WHOLESALE SALES.—The requirements of this title do not apply to the operations of a gas utility, or to proceedings respecting such operations, to the extent that such operations or proceedings relate to sales of natural gas for purposes of resale.

(d) LIST OF COVERED UTILITIES.—Before the beginning of each calendar year, the Secretary shall publish a list identifying each gas utility to which this title applies during such calendar year. Promptly after publication of such list, each State regulatory authority shall notify the Secretary of each gas utility on the list for which such State regulatory authority has ratemaking authority.

SEC. 302. DEFINITIONS.

For purposes of this title—

(1) The term "gas consumer" means any person, State agency, or Federal agency, to which natural gas is sold other than for purposes of resale.

(2) The term "gas utility" means any person, State agency, or Federal agency, engaged in the local distribution of natural gas, and the sale of natural gas to any ultimate consumer of natural gas.

(3) The term "State regulated gas utility" means any gas utility with respect to which a State regulatory authority has ratemaking authority.

(4) The term "nonregulated gas utility" means any gas utility other than a State regulated gas utility.

(5) The term "rate" means any (A) price, rate, charge, or classification made, demanded, observed, or received with respect to sale of natural gas to a gas consumer, (B) any rule, regulation, or practice respecting any such rate, charge, or classification, and (C) any contract pertaining to the sale of natural gas to a gas consumer.

(6) The term "ratemaking authority" means authority to fix, modify, approve, or disapprove rates.

(7) The term "sale", when used with respect to natural gas, includes an exchange of natural gas.

(8) The term "State regulatory authority" means any State agency which has ratemaking authority with respect to the sale of natural gas by any gas utility (other than by such State agency).

SEC. 303. ADOPTION OF CERTAIN STANDARDS.

(a) ADOPTION OF STANDARDS.—Not later than 2 years after the date of the enactment of this Act, each State regulatory authority (with respect to each gas utility for which it has ratemaking authority) and each nonregulated gas utility shall provide public notice and conduct a hearing respecting the standards established by subsection (b) and, on the basis of such hearing, shall—

(1) adopt the standard established by subsection (b)(1) if, and to the extent, such authority or nonregulated utility determines that such adoption is appropriate and is consistent with otherwise applicable State law, and

(2) adopt the standard established by subsection (b)(2) if, and to the extent, such authority or nonregulated utility determines that such adoption is appropriate to carry out the purposes of this title, is otherwise appropriate, and is consistent with otherwise applicable State law.

For purposes of any determination under paragraphs (1) and (2) and any review of such determination in any court, under section 307, the purposes of this title supplement State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

(b) ESTABLISHMENT.—The following Federal standards are hereby established:

(1) PROCEDURES FOR TERMINATION OF NATURAL GAS SERVICES.—No gas utility may terminate natural gas service to any gas consumer except pursuant to procedures described in section 304(a).

(2) ADVERTISING.—No gas utility may recover from any person other than the shareholders (or other owners) of such utility any direct or indirect expenditure by such utility for promotional or political advertising as defined in section 304(b).

(c) PROCEDURAL REQUIREMENTS.—Each State regulatory authority (with respect to each gas utility for which it has ratemaking authority) and each nonregulated gas utility, within the 2-year period specified in *subsection (c), shall adopt, pursuant to subsection (a), each of the standards established by subsection (b) or, with respect to any such standard which is not adopted, such authority or nonregulated gas utility shall state in writing that it has determined not to adopt such standard, together with the reasons for such determination. Such statement of reasons shall be available to the public.*

SEC. 304. SPECIAL RULES FOR STANDARDS.

(a) PROCEDURES FOR TERMINATION OF GAS SERVICE.—The procedures for termination of service referred to in section 303(b)(1) are procedures prescribed by the State regulatory authority (with respect to gas utilities for which it has ratemaking authority) or the nonregulated gas utility which provide that—

(1) no gas service to a gas consumer may be terminated unless reasonable prior notice (including notice of rights and remedies) is given to such consumer and such consumer has a reasonable opportunity to dispute the reasons for such termination, and

(2) during any period when termination of service to a gas consumer would be especially dangerous to health, as determined by the State regulatory authority (with respect to gas utility for which it was ratemaking authority) or nonregulated gas utility, and such consumer establishes that—

(A) he is unable to pay for such service in accordance with the requirements of the utility's billing, or

(B) he is able to pay for such service but only in installments,

such service may not be terminated.

Such procedures shall take into account the need to include reasonable provisions for elderly and handicapped consumers.

(b) ADVERTISING.—(1) For purposes of this section and section 303—

(A) The term "advertising" means the commercial use, by a gas utility, of any media, including newspaper, printed matter, radio, and television, in order to transmit a message to a substantial number of members of the public or to such utility's gas consumers.

(B) The term "political advertising" means any advertising for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matter, or with respect to any controversial issue of public importance.

(C) The term "promotional advertising" means any advertising for the purpose of encouraging any person to select or use the service or additional service of a gas utility or the selection or installation of any appliance or equipment designed to use such utility's service.

(2) For purposes of this section and section 303, the terms "political advertising" and "promotional advertising" do not include—

(A) advertising which informs natural gas consumers how they can conserve natural gas or can reduce peak demand for natural gas,

(B) advertising required by law or regulation, including advertising required under part 1 of title II of the National Energy Conservation Policy Act,

(C) advertising regarding service interruptions, safety measures, or emergency conditions,

(D) advertising concerning employment opportunities with such utility,

(E) advertising which promotes the use of energy efficient appliances, equipment or services, or

(F) any explanation or justification of existing or proposed rate schedules, or notification of hearings thereon.

SEC. 305. FEDERAL PARTICIPATION.

(a) INTERVENTION.—In addition to the authorities vested in the Secretary pursuant to any other provision of law, the Secretary, on his own motion, may intervene as a matter of right in any proceeding before a State regulatory authority which relates to gas utility rates or rate design. Such intervention shall be solely for the purpose of advocating policies or methods which carry out the purposes set forth in section 301 of this title.

(b) RIGHTS.—The Secretary shall have the same rights as any other party to a proceeding before a State regulatory authority which relates to gas utility rates or rate design.

(c) NONREGULATED GAS UTILITIES.—The Secretary, on his own motion, may, to the same extent as provided in subsections (a) through (b), intervene as a matter of right in any proceeding which relates to rates or rate design of nonregulated gas utilities.

SEC. 306. GAS UTILITY RATE DESIGN PROPOSALS.

(a) STUDY.—(1) The Secretary, in consultation with the Commission and, after affording an opportunity for consultation and comment by representatives of the State regulatory commissions, gas utilities, and gas consumers, shall study and report to Congress on gas utility rate design within 18 months after the date of the enactment of this Act. Such study shall address the effect (both separately and in combination) of the following factors upon the items listed in paragraph (2): incremental pricing; marginal cost pricing; end user gas consumption taxes; wellhead natural gas pricing policies; demand-commodity rate design; declining block rates; interruptible service; seasonal rate differentials; and end user rate schedules.

(2) The items referred to in paragraph (1) are as follows:

(A) natural gas pipeline and local distribution company load factors;

(B) rates to each class of user, including residential, commercial, and industrial users;

(C) the change in total costs resulting from gas utility designs (including capital and operating costs) to gas consumers or classes thereof;

(D) demand for, and consumption of, natural gas;

(E) end use profiles of natural gas pipelines and local distribution companies; and

(F) competition with alternative fuels.

(b) PROPOSALS.—Based upon the study prepared pursuant to subsection (a), the Secretary shall develop proposals to improve gas utility rate design and to encourage conservation of natural gas. Such proposals shall include any comments and recommendations of the Commission.

(c) TRANSMISSION TO CONGRESS.—The proposals prepared under subsection (b) shall be transmitted, together with any legislative recommendations, to each House of Congress not later than 6 months after

the date of submission of the study under subsection (a). Such proposals shall be accompanied by an analyses of—

(1) the projected savings (if any) in consumption of natural gas, and other energy resources,

(2) changes (if any) in the cost of natural gas to consumers, which are likely to result from the implementation nationally of each of such proposals, and

(3) the effects of the proposals on other provisions of this Act on gas utility rate structures.

(d) PUBLIC PARTICIPATION.—The Secretary shall provide for public participation in the conduct of the study under subsection (a) and the preparation of proposals under subsection (b).

SEC. 307. JUDICIAL REVIEW AND ENFORCEMENT.

(a) LIMITATION OF FEDERAL JURISDICTION.—(1) Notwithstanding any other provision of law, no court of the United States shall have jurisdiction over any action arising under any provision of this title except for—

(A) an action over which a court of the United States has jurisdiction under paragraph (2), or

(B) review in the Supreme Court of the United States in accordance with sections 1257 and 1258 of title 28 of the United States Code.

(2) The Secretary may bring an action in any appropriate court of the United States to enforce his right to intervene under section 305, and such court shall have jurisdiction to grant appropriate relief.

(b) ENFORCEMENT.—(1) Any person may bring an action to enforce the requirements of this title in the appropriate State court. Such action in a State court shall be pursuant to applicable State procedures.

(2) Nothing in this title shall authorize the Secretary to appeal or otherwise seek judicial review of the decisions of a State regulatory authority or to become a party to any action to obtain such review or appeal. The Secretary may participate as an amicus curiae in any judicial review of an action arising under the provisions of this title.

SEC. 308. RELATIONSHIP TO OTHER APPLICABLE LAW.

Nothing in this title prohibits any State regulatory authority or nonregulated gas utility from adopting, pursuant to State law, any standard or rule affecting gas utilities which is different from any standard established by this title.

SEC. 309. REPORTS RESPECTING STANDARDS.

(a) STATE AUTHORITIES AND NONREGULATED UTILITIES.—Not later than 1 year after the date of the enactment of this Act and annually thereafter for 10 years, each State regulatory authority (with respect to each gas utility for which it has ratemaking authority), and each nonregulated gas utility, shall report to the Secretary, in such manner as the Secretary shall prescribe, respecting its consideration of the standards established by this title. Such report shall include a summary of the determinations made and actions taken with respect to each of such standards on a utility-by-utility basis.

(b) SECRETARY.—Not later than 18 months after the date of the enactment of this Act and annually thereafter for 10 years, the Secretary shall submit a report to the President and the Congress containing—

(1) a summary of the reports submitted under subsection (a),

(2) his analysis of such reports, and

(3) his actions under this title, and his recommendations for such further Federal actions, including any legislation, regarding retail gas utility rates (and other practices) as may be necessary to carry out the purposes of this title.

SEC. 310. PRIOR AND PENDING PROCEEDINGS.

For purposes of this title, proceedings commenced by any State regulatory authority (with respect to gas utilities for which it has ratemaking authority) and any nonregulated gas utility before the date of the enactment of this Act and actions taken before such date in such proceedings shall be treated as complying with the requirements of this title if such proceedings and actions substantially conform to such requirements. For purposes of this title, any such proceeding or action commenced before the date of enactment of this Act but not completed before such date shall comply with the requirements of this title, to the maximum extent practicable, with respect to so much of such proceeding or action as takes place after such date.

SEC. 311. RELATIONSHIP TO OTHER AUTHORITY.

Nothing in this title shall be construed to limit or affect any authority of the Secretary or the Commission under any other provision of law.

TITLE IV—SMALL HYDROELECTRIC POWER PROJECTS

SEC. 401. ESTABLISHMENT OF PROGRAM.

The Secretary shall establish a program in accordance with this title to encourage municipalities, electric cooperatives, industrial development agencies, nonprofit organizations, and other persons to undertake the development of small hydroelectric power projects in connection with existing dams which are not being used to generate electric power.

SEC. 402. LOANS FOR FEASIBILITY STUDIES.

(a) LOAN AUTHORITY.—The Secretary, after consultation with the Commission, is authorized to make a loan to any municipality, electric cooperative, industrial development agency, nonprofit organization, or other person to assist such person in defraying up to 90 percent of the costs of—

(1) studies to determine the feasibility of undertaking a small hydroelectric power project at an existing dam or dams and

(2) preparing any application for a necessary license or other Federal, State, and local approval respecting such a project at an existing dam or dams and of participating in any administrative processing regarding any such application.

(b) CANCELLATION.—The Secretary may cancel the unpaid balance and any accrued interest on any loan granted pursuant to this section if he determines on the basis of the study that the small hydroelectric power project would not be technically or economically feasible.

SEC. 403. LOANS FOR PROJECT COSTS.

(a) AUTHORITY.—The Secretary is authorized to make loans to any municipality, electric cooperative, industrial development agency, nonprofit organization, or other person of up to 75 percent of the project

costs of a small hydroelectric power project. No such loan may be made unless the Secretary finds that—

(1) the project will be constructed in connection with an existing dam or dams,

(2) all licenses and other required Federal, State, and local approvals necessary for construction of the project have been issued,

(3) the project will have no significant adverse environmental effects, including significant adverse effects on fish and wildlife, on recreational use of water, and on stream flow, and

(4) the project will not have a significant adverse effect on any other use of the water used by such project.

The Secretary may make a commitment to make a loan under this subsection to an applicant who has not met the requirements of paragraph (2), pending compliance by such applicant with such requirements. Such commitment shall be for a period of not to exceed 3 years unless the Secretary, in consultation with the Commission, extends such period for good cause shown. Notwithstanding any such commitment, no such loan shall be made before such person has complied with such requirements.

(b) Preference.—The Secretary shall give preference to applicants under this section who do not have available alternative financing which the Secretary deems appropriate to carry out the project and whose projects will provide useful information as to the technical and economic feasibility of—

(1) the generation of electric energy by such projects, and

(2) the use of energy produced by such projects.

(c) Information.—Every applicant for a license for a small hydroelectric power project receiving loans pursuant to this section shall furnish the Secretary with such information as the Secretary may require regarding equipment and services proposed to be used in the design, construction, and operation of such project. The Secretary shall have the right to forbid the use in such project of any equipment or services he finds inappropriate for such project by reason of cost, performance, or failure to carry out the purposes of this section. The Secretary shall make information which he obtains under this subsection available to the public, other than information described as entitled to confidentiality under section 11(d) of the Energy Supply and Environmental Coordination Act of 1974.

(d) Joint Participation.—In making loans for small hydroelectric power projects under this section, the Secretary shall encourage joint participation, to the extent permitted by law, by applicants eligible to receive loans under this section with respect to the same project.

SEC. 404. LOAN RATES AND REPAYMENT.

(a) Interest.—Each loan made pursuant to this title shall bear interest at the discount or interest rate used at the time the loan is made for water resources planning projects under section 80 of the Water Resources Development Act of 1974 (42 U.S.C. 1962–17(a)). Each such loan shall be for such term, as the Secretary deems appropriate, but not in excess of—

(1) 10 years (in the case of a loan under section 402) or

(2) 30 years (in the case of a loan under section 403).

(b) Repayments.—Amounts repaid on loans made pursuant to this title shall be deposited into the United States Treasury as miscellaneous receipts.

SEC. 405. SIMPLIFIED AND EXPEDITIOUS LICENSING PROCEDU...S.

(a) Establishment of Program.—The Commission shall establish, in such manner as the Commission deems appropriate, consistent with the applicable provisions of law, a program to use simple and expeditious licensing procedures under the Federal Power Act for small hydroelectric power projects in connection with existing dams.

(b) Prerequisites.—Before issuing any license under the Federal Power Act for the construction or operation of any small hydroelectric power project the Commission—

(1) shall assess the safety of existing structures in any proposed project (including possible consequences associated with failure of such structures), and

(2) shall provide an opportunity for consultation with the Council on Environmental Quality and the Environmental Protection Agency with respect to the environmental effects of such project.

Nothing in this subsection exempts any such project from any requirement applicable to any such project under the National Environmental Policy Act of 1969, the Fish and Wildlife Coordination Act, the Endangered Species Act, or any other provision of Federal law.

(c) Fish and Wildlife Facilities.—The Commission shall encourage applicants for licenses for small hydroelectric power projects to make use of public funds and other assistance for the design and construction of fish and wildlife facilities which may be required in connection with any development of such project.

SEC. 406. NEW IMPOUNDMENTS.

Nothing in this title authorizes (1) the loan of funds for construction of any new dam or other impoundment, or (2) the simple and expeditious licensing of any such new dam or other impoundment.

SEC. 407. AUTHORIZATIONS.

There are hereby authorized to be appropriated for each of the fiscal years ending September 30, 1978, September 30, 1979, and September 30, 1980, not to exceed $10,000,000 for loans to be made pursuant to section 402, such funds to remain available until expended. There are hereby authorized to be appropriated for each of the fiscal years ending September 30, 1978, September 30, 1979, September 30, 1980, not to exceed $100,000,000 for loans to be made pursuant to section 403, such funds to remain available until expended.

SEC. 408 DEFINITIONS.

For purposes of this title, the term—

(1) "small hydroelectric power project" means any hydroelectric power project which is located at the site of any existing dam, which uses the water power potential of such dam, and which has not more than 15,000 kilowatts of installed capacity;

(2) "electric cooperative" means any cooperative association eligible to receive loans under section 4 of the Rural Electrification Act of 1936 (7 U.S.C. 904);

(3) "industrial development agency" means any agency which is permitted to issue obligations the interest on which is excludable from gross income under section 103 of the Internal Revenue Code of 1954;

(4) "project costs" means the cost of acquisition or construction of all facilities and services and the cost of acquisition of all land and interests in land used in the design and construction and operation of a small hydroelectric power project;

(5) "nonprofit organization" means any organization described in section 501(c)(3) or 501(c)(4) of the Internal Revenue Code of 1954 and exempt from tax under section 501(a) of such Code (but only with respect to a trade or business carried on by such organization which is not an unrelated trade or business, determined by applying section 513(a) to such organization);

(6) "existing dam" means any dam, the construction of which was completed on or before April 20, 1977, and which does not require any construction or enlargement of impoundment structures (other than repairs or reconstruction) in connection with the installation of any small hydroelectric power project;

(7) "municipality" has the meaning provided in section 3 of the Federal Power Act; and

(8) "person" has the meaning provided in section 3 of the Federal Power Act.

TITLE V—CRUDE OIL TRANSPORTATION SYSTEMS

SEC. 501. FINDINGS

The Congress finds and declares that—

(1) a serious crude oil supply shortage may soon exist in portions of the United States;

(2) a large surplus of crude oil on the west coast of the United States is projected;

(3) any substantial curtailment of Canadian crude oil exports to the United States could create a severe crude oil shortage in the northern tier States;

(4) pending the authorization and completion of west-to-east crude oil delivery systems, Alaskan crude oil in excess of west coast needs will be transshipped through the Panama Canal at a high transportation cost;

(5) national security and regional supply requirements may be such that west-to-east crude delivery systems serving both the northern tier States and inland States, consistent with the requirements of section 410 of the Act approved November 16, 1973 (87 Stat. 594), commonly known as the Trans-Alaska Pipeline Authorization Act, are needed;

(6) expeditious Federal and State decisions for west-to-east crude oil delivery systems are of the utmost priority; and

(7) resolution of the west coast crude oil surplus and the need for crude oil in northern tier States and inland States require the assignment and coordination of overall responsibility within the executive branch to permit expedited action on all necessary environmental assessments and decisions on permit applications concerning delivery systems.

SEC. 502. STATEMENT OF PURPOSES.

The purposes of this title are—

(1) to provide a means for—

(A) selecting delivery systems to transport Alaskan and other crude oil to northern tier States and inland States, and

(B) resolving both the west coast crude oil surplus and the crude oil supply problems in the northern tier States;

(2) to provide an expedited procedure for acting on applications for all Federal permits, licenses, and approvals required for the construction and operation or any transportation system approved under this title and the Long Beach-Midland project; and

(3) to assure that Federal decisions with respect to crude oil transportation systems are coordinated with State decisions to the maximum extent practicable.

SEC. 503. DEFINITIONS.

As used in this title—

(1) The term "northern tier States" means the States of Washington, Oregon, Idaho, Montana, North Dakota, Minnesota, Michigan, Wisconsin, Illinois, Indiana, and Ohio.

(2) The term "inland States" means those States in the United States other than northern tier States and the States of California, Alaska, and Hawaii.

(3) The term "crude oil transportation system" means a crude oil delivery system (including the location of such system) for transporting Alaskan and other crude oil to northern tier States and inland States, but such term does not include the Long Beach-Midland project.

(4) The term "Long Beach-Midland project" means the crude oil delivery system which was the subject of, and is generally described in, the "Final Environmental Impact Statement, Crude Oil Transportation System: Valdez, Alaska, to Midland, Texas (as proposed by Sohio Transportation Company)", the availability of which was announced by the Department of the Interior in the Federal Register on June 1, 1977 (42 Fed. Reg. 28008).

(5) The term "Federal agency" means an Executive agency, as defined in section 105 of title 5, United States Code.

SEC. 504. APPLICATIONS FOR APPROVAL OF PROPOSED CRUDE OIL TRANSPORTATION SYSTEMS.

The following applications for construction and operation of a crude oil transportation system submitted to the Secretary of the Interior by an applicant are eligible for consideration under this title:

(1) Applications received by the Secretary before the 30th day after the date of the enactment of this Act.

(2) Applications received by the Secretary during the 60-day period beginning on the 30th day after the date of the enactment of this Act, if the Secretary determines that consideration and review of the proposal contained in such application is in the national interest and that such consideration and review could be completed within the time limits established under this title.

An application under this section may be accepted by the Secretary only if it contains a general description of the route of the proposed system and identification of the applicant and any other person who, at the time of filing, has a financial or other interest in the system or is a party to an agreement under which such person would acquire a financial or other interest in the system.

SEC. 505. REVIEW SCHEDULE.

(a) ESTABLISHMENT.—The Secretary of the Interior, after consultation with the heads of appropriate Federal agencies, shall establish an expedited

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schedule for conducting reviews and making recommendations concerning crude oil transportation systems proposed in applications filed under section 504 and for obtaining information necessary for environmental impact statements required under section 102 of the National Environmental Policy Act of 1969 (42 U.S.C. 4332) with respect to such proposed systems.

(b) ADDITIONAL INFORMATION.—(1) On his own initiative or at the request of the head of any Federal agency covered by the review schedule established under subsection (a), the Secretary of the Interior shall require that an applicant provide such additional information as may be necessary to conduct the review of the applicant's proposal. Such information may include—

(A) specific details of the route (and alternative routes) and identification of Federal lands affected by any such route;

(B) information necessary for environmental impact statements; and

(C) information necessary for the President's determination under section 507(a).

(2) If, within a reasonable time, an applicant does not—

(A) provide information required under this subsection, or

(B) comply with any requirement of section 304 of the Federal Land Policy and Management Act of 1976 (90 Stat. 2765; 43 U.S.C. 1734),

the Secretary of the Interior may declare the application ineligible for consideration under this title. After making such a declaration, the Secretary of the Interior shall notify the applicant and the President of such ineligibility.

(c) RECOMMENDATIONS OF THE HEADS OF FEDERAL AGENCIES.—(1) Pursuant to the schedule established under subsection (a), heads of Federal agencies covered by such schedule shall conduct a review of a proposed crude oil transportation system eligible for consideration under this title and shall submit their recommendations concerning such systems (and the bases for such recommendations) to the Secretary of the Interior for submission to the President. After receipt of such recommendations and before their submission to the President, the Secretary of the Interior shall provide an opportunity for comments in accordance with paragraph (2). The Secretary of the Interior shall forward such comments to the President with the recommendations—

(A) in the case of applications filed under section 504(1), on or before December 1, 1978, and

(B) in the case of applications filed under section 504(2), on or before the 60th day after December 1, 1978.

(2)(A) After receipt of recommendations under paragraph (1) the Secretary of the Interior shall provide appropriate means by which the Governor and any other official of any State and any official of any political subdivision of a State, may submit written comments concerning proposed crude oil transportation systems eligible for consideration under this title.

(B) After receipt of recommendations referred to in subparagraph (A), the Secretary of the Interior shall make such comments and recommendations available to the public and provide an opportunity for submission of written comments.

(d) REVIEW BY THE FEDERAL TRADE COMMISSION; EFFECT ON THE ANTITRUST LAWS.—(1) Promptly after he receives an application for a proposed crude oil transportation system eligible for consideration under

this title, the Secretary of the Interior shall submit to the Federal Trade Commission a copy of such application and such other information as the Commission may reasonably require. The Commission may prepare and submit to the President a report on the impact of implementation of such application upon competition and restraint of trade and on whether such implementation would be inconsistent with the antitrust laws. Such report shall be made available to the public. Nothing in this subsection shall be construed to prevent the President from making his decision under section 507(a) in the absence of such report.

(2) Nothing in this title shall bar the Attorney General or any other appropriate officer or agent of the United States from challenging any anticompetitive act or practice related to the ownership, construction, or operation of any crude oil transportation system approved under this title. The approval of any such system under this title shall not be deemed to convey to any person immunity from civil or criminal liability or to create defenses to actions under the antitrust laws and shall not modify or abridge any private right of action under such laws.

(e) FILING AND REVIEW OF PERMITS, RIGHTS-OF-WAY APPLICATIONS, ETC., NOT AFFECTED.—Nothing in this title shall be construed to prevent the acceptance and review by any Federal agency of any application for any Federal permit, right-of-way, or other authorizations under other provisions of law for a crude oil transportation system eligible for consideration under this title; except that any determination with respect to such an application may be made only in accordance with the provisions of section 509(a).

SEC. 506. ENVIRONMENTAL IMPACT STATEMENTS.

(a) PREPARATION OF ENVIRONMENTAL IMPACT STATEMENTS.—Any Federal agency required under section 102 of the National Environmental Policy Act of 1969 (42 U.S.C. 4332) to issue an environmental impact statement concerning a proposed crude oil transportation system eligible for consideration under this title shall, in preparing such statement, utilize, to the maximum extent practicable and consistent with such Act, appropriate data, analyses, conclusions, findings, and decisions regarding environmental impacts developed or made by any other Federal or State agency.

(b) FILING OF ENVIRONMENTAL IMPACT STATEMENTS.—On or before December 1, 1978, all environmental impact statements concerning proposed crude oil transportation systems eligible for consideration under this title and required under section 102 of the National Environmental Policy Act of 1969 shall be completed, made available for public review and comment, revised to the extent appropriate in light of such comment, and submitted to the President and the Council on Environmental Quality; except that in the case of any environmental impact statement concerning any crude oil transportation system which is eligible for consideration and which was filed under section 504(2) of this title, such actions may be taken not later than 60 days after December 1, 1978.

(c) REPORT OF THE COUNCIL ON ENVIRONMENTAL QUALITY.—Promptly after receiving an environmental impact statement referred to in subsection (b) for a crude oil transportation system, the Council on Environmental Quality shall submit to the President a report on the Council's opinion concerning such statement and concerning other matters related to the environmental impact of such system.

Section 115. Special rules for standards

Subsection (a) describes how the cost of service is to be determined by the State regulatory authority or the nonregulated utility, as the case may be, when they undertake the consideration and make the determination with respect to the standard on cost of service, as required under section 111. The conference agreement includes the requirement that the methods prescribed for determining the cost of providing electric service shall reflect differences in cost-incurrence attributable to differences in customer, demand, and energy charges.

The conferees chose the phrase "take into account" so as not to imply a preference for a State regulatory authority or a nonregulated electric utility to follow any specific costing methodology for determining cost of service. The State regulatory authority or nonregulated utility has the discretion to select which costing methodology or methodologies it chooses, consistent with State law. However, the conferees feel that the matters specified in paragraphs (A) and (B) of subsection (1) are factors to be taken into consideration in determining costs of service, especially with respect to time of day, interruptible, and seasonal rates. State utility commissions and utilities should apply the conclusions of taking these factors into account in a manner best calculated to fulfill the purposes of this title.

Where the conference substitute states in subsection (a)(2)(A) that additional capacity is added to meet peak demand relative to base demand, the conferees intend that capacity be measured both in terms of the need to construct additional generation facilities and in terms of wear and tear on existing facilities caused by additional demand.

The purpose of subsection (b) is to explain how to determine whether a time of day rate is cost effective for a class of electric consumers, as section 111(c)(3) provides that the standard on time of day rates does not apply if the rates have been determined not to be cost-effective for a class of electric consumers with respect to the specified class.

In weighing whether time of day rates are cost effective, the long-run benefits of such rate to the utility and the class of electric consumers concerned should be measured against the metering costs and other costs associated with the use of such rates. The conferees intend long-run benefits to include savings by reason of using less expensive, rather than more expensive, fuels as well as using more efficient generation facilities rather than less efficient generation facilities. In terms of metering costs and other costs associated with the use of such rates, the conferees intend that the term "other costs" be interpreted narrowly and include only those costs directly involved in using these rates (such as added costs due to more complex billing services) and not costs indirectly involved such as the start up costs involved in fashioning a time of day rate structure for initial consideration in a rate case. These start up costs are already incurred before a decision is made to implement time of day rates, hence they are not a consequence of such decision. This test is not intended to be an exclusive test for time of day rates. States could still implement time of day rates pursuant to State authority even if the implementation of the Federal standard was determined not appropriate to carry out the purposes of section 101.

Nothing in this subsection prohibits the offer of a time of day rate to any electric consumer willing to pay the metering costs, notwithstanding a determination that the Federal standard on time of day rates is not cost effective with respect to the class of which that consumer is a member.

Similarly, subsection (c) explains how the determination is made that a load management technique under section 111 is cost-effective. The determination should focus on the reduction of maximum kilowatt demand on the electric utility and long-run cost savings to the utility versus long-run costs to the utility associated with implementation of the technique. Although individual consumers may wish to install load management techniques to reduce their individual peak demand and thereby reduce overall costs of electric energy supplied to them, the conferees intend the main focus of this examination to relate to the reduction of the utility's peak demand, when it is most likely that generation is most expensive.

Subsection (d) explains the special rule on when a State regulatory authority or nonregulated electric utility should determine separate metering appropriate. If the occupant of the individual unit of the building does not have control over any portion of the electric energy used in the unit or if he does have such control but the costs of metering are more than the long-run benefits to the consumer, then separate meters would not be appropriate in each separate unit in the building.

Subsection (e) describes the requirements with respect to automatic adjustment clauses which meet the standard in section 113(b)(3).

In order to increase any rate pursuant to such a clause which meets the standard, the clause must be reviewed at least every 4 years by the State regulatory authority (with respect to each utility it regulates) and by the nonregulated electric utility. That review must be made in an evidentiary hearing. Based on that hearing a determination must be made by the State regulatory authority or nonregulated utility, as appropriate, as to whether or not the clause effectively provides incentives for the efficient use of resources by the affected utility and as to whether or not costs not subject to periodic fluctuations and therefore not susceptible to precise determinations in rate cases prior to the time such costs are incurred are incorporated in the automatic adjustment clause. The incentives include the economical purchase and use of electric energy acquired from another utility and fuel. In addition, the clause must be reviewed at least biennially at an evidentiary hearing to insure the maximum economies in those operations and purchases that affect the rates of a utility. The latter review shall include an examination of the practices of the affected electric utility which relate to the costs included in the clause. In appropriate cases, an audit of such costs may be required. This review shall also include such reports as necessary to carry out the review, including disclosure of any ownership or corporate relationship between the affected utility and the seller of fuel, electric energy, and other items covered by the clause.

The conferees, in adopting these provisions, do not endorse or encourage the use of automatic adjustment clauses nor do they mean to suggest that the use of automatic adjustment clauses is inappropriate. The conferees do not indicate a preference of any particular item for inclusion or exclusion in such a clause. The conferees intend that adoption of this standard should not in any way bar the use of the rate setting procedure known as cost of service indexing, such as being currently used in the State of New Mexico for retail rates.

In the last sentence of the definition of the term "automatic adjustment clause," the conference substitute excludes from the definition the temporary rate schedule which goes into effect pending final determination of the lawfulness of the rate application in a rate case.

Subsection (f) closely follows the House bill with minor technical changes. The conferees felt that the ability of the electric consumer to make the right decisions regarding the use of electric energy depends greatly on the information available to him. This is especially true if time of day rates are in place. The success of such a rate practice depends upon consumers voluntarily moving from on-peak use to off-peak use where they have a choice as to when to use the electricity. The statement given to the consumer pursuant to subsection (f)(1) could also include a listing of his rights and responsibilities as an electric consumer. Paragraph (3) of this subsection sets forth a consumer's right to receive information on his past year's consumption. If this information has already been provided on the bills received by the consumer during the time for which the request is made, the State regulatory authority on nonregulated utility could take that fact into account in deciding whether to adopt this part of the standard on information to consumers.

With respect to procedures for termination of service specified in subsection (g), the conferees modified the House provision to assure that consumers have a reasonable opportunity to dispute the reasons for termination after they receive notice. The electric consumer should be given adequate notice of the proposed termination, together with a clear and concise statement of such consumer's rights and remedies, and an adequate opportunity to dispute the payment and the reasons for termination. Such an opportunity could include a hearing or a less formal procedure that would allow the consumer an effective opportunity to dispute those reasons.

In addition, the standard would preclude termination of service to residential electric consumers, including tenants and homeowners, where such consumers establish an inability to pay for the service within a reasonable period of time and there is a danger to the consumer or someone in the household. In such case termination should not occur if payment can be made in installments rather than in a lump sum.

For purposes of the standard on advertising, subsection (h) defines "advertising" in general and then defines by inclusion and by exclusion "political advertising" and "promotional advertising". These definitions are derived from the language of the House bill, except that "institutional advertising" is not covered by the standard, and justification of existing or proposed rate schedules is not covered as well as advertising concerning employment, or services which promote energy conservation.

Section 116. Reports respecting standards

This section concerns reporting requirements applicable to State regulatory authorities, nonregulated utilities, and the Secretary of

Energy. The conferees expect that through the reports made under this section, the progress of the States will be accurately measured and reported to Congress to provide a basis for legislative oversight by the Congress.

Section 117. Relationship to State law

The conferees agreed to adopt the provision from the House bill found in subsection (a) of this section with the inclusion of the words "or less than" after "in excess of". This is an expression by the conferees that determinations with respect to rate of return and overall revenues permitted to utilities is exclusively a matter of State law, and the principal Federal concern is with the structure of the rates to different classes of consumers as specified in the rate schedule.

Subsection (b) of this section states that State regulatory authorities and nonregulated utilities are not prohibited from deviating from any standard identified in this title, adopting additional standards, more stringent standards, less stringent standards, or only some of the standards or modifying these standards in applying them to rate schedules of particular utilities to the extent permitted by State law. The conferees feel that the standards spelled out in this legislation are worthy of careful consideration but recognize the need to adapt these standards, after such consideration, to local conditions and particular situations. This subsection is an expression of the flexibility the conferees intend that the States will continue to have in adopting at the State level rules or standards affecting electric utilities.

Subsection (c) of this section contains a conforming provision which clarifies which law is meant to otherwise apply in the case of Federal agencies which are electric utilities and in the case of the TVA which is both an electric utility and a State regulatory authority within the meaning of the Act. Since these agencies are now not subject to State law, the conferees do not wish their judgments with regard to whether or not the standards contained in section 111(d) are appropriate to carry out the purposes of this title or to whether or not to adopt the standards contained in section 113(b) to be bound by State law but rather the applicable law which governs their actions, namely Federal law. The statutory requirements with regard to ratemaking and other matters which apply to these Federal agencies would continue to apply and would still be required to be followed.

SUBTITLE C—INTERVENTION AND JUDICIAL REVIEW

Section 121. Intervention in proceedings

In order to initiate the consideration, or provide for participation by the Secretary of Energy and certain other persons in the consideration, of any standard under subtitle B or any other concept which may contribute to the achievement of the purposes of the title, this section creates a Federal right of participation and intervention in ratemaking proceedings or other appropriate regulatory proceedings conducted by a State regulatory authority or by a nonregulated electric utility. The conferees adopted this provision in recognition of the reliance they place on intervention and participation in these proceedings to further the purposes of this title.

The Secretary of Energy, any affected utility, or any electric consumer of an affected utility may intervene under this provision to initiate or participate in the consideration of one or more of the standards established by this title or other concepts which contribute to the achievement of the purposes of the title. The conferees intend for the term intervention to be interpreted broadly to include intervention or participation at the beginning of a proceeding or otherwise but do not intend for such term to connote a right to initiate a proceeding.

The conferees intend that the phrase "other concepts which contribute to the achievement of the purposes of this title" be construed broadly so that no one will have to prove his case in advance before being allowed to intervene. Any issue which may contribute to the purposes of the title should be given consideration if it may contribute to these purposes. The procedures for the type of intervention are left to State law.

This section ties in with section 112(a) in the sense that the Federal right to intervene can result in a request for consideration of a particular standard specified in section 111(d), in which case a section 111(a) determination should be made. Again, section 112(a) contains a provision by which this determination may be based on appropriate prior determinations and evidence so as to avoid unnecessary delay and expense. However, the conferees are relying on the State courts (except as otherwise specified in section 123) to review these proceedings and insure that proper procedures under this Act and State law are followed.

The conferees intend that the phrase "affected electric utility" means any utility which is subject to regulation by the same regulatory authority which utility might be affected by precedents set in a case relating to another utility. This term would also include utilities permitted to participate or intervene under State law.

Subsection (b) of this section deals with the participant's or intervenor's access to relevant information available to other parties to the proceeding.

It is the intention of the conferees as expressed in subsection (c) that the right to intervene or participate created by this section vest as of the date of enactment of the legislation. Intervenors or participants should be permitted to intervene or participate in proceedings which are ongoing on that date only to the extent such intervention would be timely and not disruptive of the proceeding and is in accordance with otherwise applicable law. Within this constraint, the State regulatory authority or nonregulated utility should provide maximum opportunity under State law to participate in ongoing proceedings. Federal courts will be available to interpret the actions under this provision of Federal law after protest in a State court, as provided in section 123(a)(2)(B), or directly in the case of the Secretary of Energy.

Section 122. Consumer representation

Section 122 is a modified version of the House provision with respect to consumer representation. The purpose of this section is to provide a mechanism to assure that the interests of electric consumers will be represented at the State level in proceedings dealing with the standards set forth in subtitle B. The mechanism chosen for this

purpose is either of two options. One makes the utility liable to provide compensation directly to electric consumers who substantially contribute to the approval, in whole or in part, of a position advocated by the consumer in a proceeding concerning the utility relating to any standard set forth in this title by creating a right of action against the utility. The second option provides that the State or State regulatory authority or nonregulated utility may have a program to otherwise provide adequate compensation to persons described in subsection (b). Such a program may include an adequately funded office of public counsel which adequately represents the interests of persons described in paragraphs (1) and (2) of subsection (b).

The conferees intend that the phrase "substantially contribute to the approval, in whole or in part," be broadly construed by the State agencies, nonregulated utilities, and the courts to effectively provide for compensation commensurate with the contribution to the approval of one or more of the standards.

In section 122(a)(3)(A), the State regulatory authority or nonregulated electric utility may include a preliminary proceeding to require that (1) as a condition of receiving compensation under the procedure under paragraph (2), the consumer demonstrate that, but for the ability to receive the award of fees, participation in such proceeding may be a significant financial hardship for the consumer, and (2) persons with same or similar interests have a common legal representative in the proceeding as a condition to receiving compensation. The conferees intend that phrase "significant financial hardship" is to be construed broadly, the determination not being restricted to whether the consumer can participate in that particular case but give consideration to other financial burdens, including those associated with intervention in other cases. The intention is not to compensate intervenors who can afford to intervene in any event if the State regulatory authority or nonregulated utility adopts the procedures in subsection (a)(2) or (a)(3)(A).

Subsection (d) provides that any Federal payments to intervenors under this section are subject to the appropriation process.

Subsection (e) states that nothing in this section shall affect or restrict any rights of any participant in any proceeding under any other applicable law or rule of law. Payment of funds pursuant to this section does not permit the State regulatory authority to control the nature of the legal representation or manner of handling of a case in any proceeding. Payment of costs of participation are not intended to be used as method to dictate who should represent a participant or intervenor.

Section 123. Judicial review and enforcement

This section provides for the judicial review of any actions arising under subtitles A, B, or C and for enforcement of the requirements of these subtitles. In general, as stated in subsection (a), the jurisdiction of the Federal courts is limited by this section; review and enforcement is primarily in the State courts. Federal court review can occur in only limited instances described in this section; the provisions of appellate review under title 28 of the U.S.C. do not apply to actions arising under subtitle A, B, or C except as specifically provided for in this section.

With respect to subsection (a)(2) of this section, the Supreme Court would have jurisdiction as provided in existing law to consider any action upon appeal from the highest court of any State.

Under subsection (b), the Secretary may enforce his right to intervene or participate under section 121(a) in Federal courts. Also any electric utility or electric consumer who has a right to intervene under section 121(a) and who is denied that right may bring an action in Federal court to enforce that right if he has first tried to enforce that right in State court. Such person may also appeal through the State court system. The conferees wanted to make enforcement of the right to participate and intervene in proceedings before State regulatory authorities and nonregulated utilities as rapid as possible consistent with the provisions of this title. Intervenors or participants must first go to State court to enforce this right, but are not required to appeal through the State court system. In fact, if the State authority or nonregulated utility has refused him the right to intervene under section 121(a), even a denial on the grounds that the appeal is premature or interlocutory and therefore not appropriate at that time, is enough to satisfy this requirement. The Federal Court can only require that the intervenor be allowed to participate to the extent provided under this title. It cannot require any particular outcome from the intervention, nor that any issue raised by an intervenor be considered appropriate.

With regard to this section, the conferees do not intend to foreclose Federal courts from jurisdiction to review cases involving electric utility rates which do not involve actions arising under subtitle A, B, or C. Where the Federal Government has authority in law to cause review of electric rates in Federal court as a purchaser of electric energy, this subsection is not meant to limit this review in Federal courts, except that the Federal courts will have no jurisdiction with respect to issues arising under subtitle A, B, or C.

Subsection (c)(1) deals with review of determinations and enforcement of requirements of subtitle A, B, or C in State courts with respect to utilities which are not Federal agencies. The second sentence provides for enforcement authority. This enforcement provision contemplates enforcement (including by writ of mandamus) of obligations of State regulatory authorities and nonregulated utilities to hold hearings, to make determinations, and to comply with all the other requirements of subtitles A, B, and C. The enforcement authority does not provide an independent authority to attack a final determination of a regulatory authority or a nonregulated electric utility which is reviewed under the first sentence of the subsection.

The conferees intend that any appeal from a final determination by a State regulatory authority or nonregulated utility will be in that State's courts and the scope of review will be pursuant to State law. The findings and determinations by the courts are reviewable under the substantive standards of review as established under State law, as such standards are supplemented by the purposes of this title although State law is supplemented in this respect, discretion under otherwise applicable State law is not restricted. Procedures for State court review (including burdens of proof) shall be as provided by State law except as may be modified in section 123(c).

Subsection (c)(2) of this section reserves review of Federal agency action under subtitles A, B, and C in Federal courts to the same extent as provided in existing law. The conferees, in generally choosing to rely on State courts, did not wish to remove electric utilities which are Federal agencies from their traditional forum for review.

Subsection (c)(3) provides that the Secretary of Energy may file an amicus curiae brief in a judicial review of a proceeding of a State regulatory authority or nonregulated utility regardless of whether he participated in the original proceeding.

Section 124. Prior and pending proceedings

This section deals with the question of whether and to what extent prior or pending proceedings will be treated as fulfilling the requirements of this title. It states that proceedings commenced by State regulatory authorities and nonregulated utilities before the date of enactment of this title and actions taken in such proceedings shall be treated as complying with the requirements of this title if the proceedings and actions substantially comply with the requirements of this title.

The conferees recognize that several State regulatory authorities and nonregulated utilities may have already addressed one or more of these standards before enactment of this legislation. The conferees also recognize that those responsible for these proceedings could not have anticipated in detail the requirements of this title. The fact that the prior proceeding did not permit the full right of participation and intervention as required by section 121 of this title does not automatically constitute the absence of substantial conformance. It is not the intention of the conferees that the standards be reconsidered at great expense and without purpose if the original proceedings substantially conformed with the requirements of this title. The essential feature of the process contemplated by the conferees in this title with respect to the standards established by section 111(d) is that there be utility-by-utility analysis of the appropriateness of these standards to carry out the purposes specified in section 101. Of course, no one could precisely follow the exact consideration required here because the legislation did not exist. Therefore, the State regulatory authorities and nonregulated utilities will have to determine whether they substantially conformed to the requirements of the title and the courts will be able to review this determination.

This section also states that any proceeding or action pending on the date of enactment of this Act shall comply with the requirements of this title, to the maximum extent practicable, with respect to so much of such proceeding or action as takes place after the date of enactment. If a proceeding has been begun prior to such date, nothing here would require restarting the entire proceeding to give any person a right to participate or intervene if such right would be untimely, as stated in section 121(c). Nor does this section require notice in accordance with the requirements of this title if the proceeding had begun before enactment. However, if no determination had been made, then the requirements in section 111(d) with regard to a written determination which is based upon findings included in such determination and upon evidence presented at the hearing, and which is available to the public, should be followed.

Subtitle D—Administrative Provisions

Section 131. Voluntary guidelines

This section gives the Secretary the authority to prescribe voluntary guidelines respecting the standards established by subtitle B. The conferees intend that by using the word "prescribe", the Secretary utilize a procedure which involves significant input from concerned persons in formulating these guidelines. These guidelines are not to be construed as binding or mandatory on the State regulatory authorities, nonregulated utilities, or on the courts in interpreting the standards. These guidelines may not expand the scope or legal effect of the standards. The Secretary would have no authority to enforce these guidelines in court. Rather, the guidelines would be voluntary in nature. They are the Secretary's opinion of the standards, which opinion the States would weigh as they would other opinions on how these standards should be interpreted.

The House bill contained a section that established a "Utility Advisory Committee" to advise the Federal Energy Regulatory Commission respecting certain duties and functions assigned to the Commission. There was no comparable Senate provision. The conferees did not adopt this section. Rather, the conferees anticipate that the Secretary of Energy will consult with the State regulatory authorities, nonregulated utilities, and other entities in prescribing any guidelines under this section.

Section 132. Responsibilities of Secretary of Energy

The conferees agreed to adopt a modified version of the language of the House provision that requires the Secretary of Energy to inform the State regulatory authorities and nonregulated utilities about data or information that would assist them in carrying out the provisions of this title.

In addition the conferees added a subsection from the House bill authorizing the Secretary of Energy to provide such technical assistance as he determines appropriate to any State regulatory authority, if it requests it. A subsection authorizing appropriations for this technical assistance is included.

Section 133. Gathering information on costs of service

The purpose of this section is to require electric utilities to gather information (under rules prescribed by the Commission) which is necessary to determine the costs associated with providing electric service and to provide for the filing and publication of this information. The conferees intend that good information with regard to costs of providing service must be readily available on a timely basis to everyone concerned. The Commission is given 180 days to promulgate these rules so as to begin the process of collecting and publishing this information during the consideration and determination phase of this program within the first 2 years after the date of enactment. Subsection (a) contains a list of four items the Commission is mandated to include in these rules, these items being basic to any determination with respect to the cost of providing electric service. These four items are not meant to be an exclusive list of what the Commission could require to be gathered under these rules but rather are intended to be minimum requirements.

The conferees agreed to make this section enforceable under section 12 of the Energy Supply and Environmental Coordination Act of 1974. If this section 12 expires at any time, the legislation specifically authorizes continued use of it after that date for purposes of enforcing any violation of this section 133. Nothing done in this section affects the authority of the Commission or the Department of Energy under section 11 of E.S.E.C.A. or other statutes to collect and publish energy information.

Under subsection (c) of this section, the electric utilities are required to file the information gathered pursuant to subsection (a) with the Commission and the State regulatory authorities, and make it available to the public, in a manner and form described by the Commission. It is the intention of the conferees that such information be filed with respect to each class of electric consumers and not with respect to any particular electric consumer. The conferees intend to protect individual bills and consumption patterns of individuals from disclosure because such information may be proprietary information. The Commission and the State regulatory authority, however, shall be able to review the individual data to verify accuracy of information filed with them and for enforcement purposes.

The information gathered under subsection (a) shall be coordinated with the filing requirements under subsection (c) so as to reduce unnecessary burdens.

Section 134. Relationship to other authority

This section provides that nothing in this title shall be construed to limit or affect any authority of the Secretary or the Commission under any other provision of law. This is not intended by the conferees to give the Secretary authority to raise issues related to the requirements of this title in Federal court pursuant to the general jurisdiction provisions of title 28, United States Code. Judicial review of issues related to this title has been provided for under section 123, and such review can occur only pursuant to that provision. His right to use those provisions with regard to actions permissible to be brought under them would still pertain as long as issues related to this title were not entertained.

Subtitle E—State Utility Regulatory Assistance

Section 141. Grants to carry out titles I and III

Section 141 amends the Energy Conservation and Production Act to authorize the Secretary to make grants to State utility regulatory commissions and nonregulated utilities to carry out duties and responsibilities under this title of the conference substitute.

The Secretary, as expressed in subsection (b), may establish only such requirements with respect to these grants as are necessary to assure that grants are expended solely to carry out the duties and responsibilities under the legislation. The conferees included this provision to assure that the Secretary could not attempt, by means of grants, to influence the outcome of deliberations in the States concerning these standards.

Additionally subsection (c) states that these grants are to be in addition to and not in substitution for funds otherwise available to the

State regulatory authorities or nonregulated utilities to carry out these functions.

Finally, subsection (d) states that, in apportioning the funds among the States, any disbursal of funds must not result in any State, as a whole, receiving for its State commission or nonregulated utilities located in it, more than an amount determined by dividing the total amount available under this program equally among States from which applications are received, except that no State regulatory authority or nonregulated utility can receive more funds than the Secretary, pursuant to his authority under subsections (b) and (c), determines necessary to carry out the duties and responsibilities under this title.

The conferees intend that the funds provided to the State regulatory authorities and nonregulated electric utilities under this section not be used primarily for paying personnel salaries and related costs.

Section 142. Authorizations

Section 142 adds a new section 208 to the Energy Conservation and Production Act to provide certain authorizations of appropriations. The first authorization deals with assistance to carry out duties and responsibilities under the conference substitute. Since most of these duties and responsibilities will occur for the first two or three years after enactment, the conferees targeted the authorization to meet this start-up need. The conferees do not intend to make this assistance program a permanent one, but rather to help the States carry out these new responsibilities and duties until they can find ways to deal with them at the State level.

The other two authorizations deal with programs that have been authorized since August 14, 1976, the date of enactment of the Energy Conservation and Production Act.

Section 143. Conforming amendments

This section contains technical amendments to conform title II of the Energy Conservation and Production Act to the transfer of functions made by section 301 of the Department of Energy Organization Act, which section transferred authorities of the Administrator of the Federal Energy Administration to the Secretary of the Department of Energy.

TITLE II—CERTAIN FEDERAL ENERGY REGULATORY COMMISSION AND DEPARTMENT OF ENERGY AUTHORITIES

Section 201. Definitions

Section 201 amends the Federal Power Act to insert a number of new definitions in that Act. These definitions are taken from the House bill and Senate amendment with technical and conforming changes. They supersede the definitions contained in section 3 with respect to the Federal Power Act amendments. The section 3 definitions do not apply for purposes of such amendments.

With regard to the definition of "small power production facility", the conferees intend, for purposes of maintaining status as a small power production facility, that the phrase "primary energy source" does not preclude the use of gas or oil in a facility for the generation of electricity during scheduled outages.

It is the intention of the conferees that the term "waste" as used in the definition of "small power production facility" includes wood and liquid or solid waste. The power production capacity of the facility means the rated capacity of the facility. The conferees added the term "primary energy source" to this definition in recognition of the fact that a facility using waste, biomass, or renewable resources, or any combination thereof as the primary fuel might nevertheless require the use of oil or natural gas or other nonrenewable fuels in emergencies or in outages or to start the unit, test it, stabilize the flame or control the operation of the unit or for other minor uses.

The definition of small power production facility includes solar electric systems, wind electric systems, systems which produce electric energy from waste or biomass, and electric energy storage facilities. The conferees intend that water be included within the meaning of the term renewable resources with respect to hydroelectric facilities at existing dams.

The terms "qualifying small power production facility" and "qualifying cogeneration facility" exclude facilities which are owned by a person who is primarily engaged in the generation or sale of electric power. Electric utilities may participate in an entity which owns such facilities with other persons and such entity could qualify under these definitions. The test of this case is whether the entity which owns the facility is primarily engaged in the generation or sale of electric power other than in connection with its ownership of the cogeneration facilities or small power production facilities.

The new paragraphs 17(C) and 18(B) of the definitions provide that the Commission shall determine, by rule, on a case-by-case basis, or otherwise, that a small power production facility or cogeneration facility is a qualifying small power production facility or a qualifying cogeneration facility, as the case may be. The purpose of this determination is to provide a means to insure that such a facility is identified through Commission action for purposes of showing that it is in fact included in any exemption under section 210(e) of the Federal Power Act. Such determination would also prevent such facility from being challenged concerning the application of such exemption to it.

The conferees intend, in providing for requirements respecting qualifying facilities to be established by the Commission by rule, that the Commission provide requirements under which a person may ascertain in advance of construction or operation of any facility whether or not such facility will meet the criteria contained in these definitions.

The Commission should prescribe these rules as soon as practicable after enactment.

The language in these definitions relating to fuel use and fuel efficiency may not always be applicable as some power production facilities (such as hydroelectric facilities) may not use fuel.

It is also the intention of the conferees that the definitions of "qualifying cogeneration facility" and "qualifying small power productio. ...ility" will not be construed as prohibiting or discouragin electric utilities from cogenerating.

Section 202. Interconnection

This section amends the Federal Power Act to add a new sectio 210 at the end of part II of that Act. It describes who may apply t the Commission for an order requiring: an interconnection and cer tain other specified actions. In addition, this section describes who i subject to such orders and what procedures the Commission must employ, the criteria they must use, and the action required or permitted to be taken by the Commission with respect to such applications. It also provides for issuance of an order by the Commission on its own motion.

Federal power marketing agencies are not included as targets of interconnection orders under this section.

The conferees recognize that other provisions of law provide adequate authority for the Secretary to arrange for interconnections between utilities (or other persons) and the Federal power marketing entities which are under the jurisdiction of the Department of Energy. The conferees expect that the Secretary will adopt procedures permitting persons to request interconnection of the systems of such power marketing entities under the jurisdiction of the Department of Energy with other utilities or other persons.

Under subsection (a)(1) of new section 210, actions under subparagraphs (C) or (D) may be ordered only if actions have been ordered under subparagraph (A) or (B). Subparagraph (B) contains a listing of examples of reasons by which an interconnection may be inadequate but it is not the conferees' intention that this list represent an exclusive list.

The conferees believe that if the Commission modifies, in any order issued under this section, the action applied for, it must state its reasons therefore and base such modification on the record before it.

The conferees intend that the reference to efficiency of use of facilities and resources in subsection (c)(2)(B) include efficient use of both existing facilities and resources and facilities and resources reasonably contemplated to be used in the future. The conferees also intend that the term "resources" include capital resources.

Subsection (c) provides that no order may be issued under subsection (a) unless the Commission determines that the order: (1) is in the public interest; (2) would encourage overall conservation of energy or capital, or optimize the efficiency of use of facilities and resources, or improve the reliability of one or more of the utility systems to which the order applies; and (3) meets the requirements of section 212.

In the conference substitute, the conferees extended the right to apply for interconnection orders to certain cogenerators and small power producers. Operators of these facilities may own several qualifying facilities which meet standards set forth by the Commission and also own facilities which do not meet these standards (and therefore are not qualifying facilities). It is the intent of the conferees that orders issued under this section be applicable to qualifying cogeneration facilities and qualifying small power production facili-

ties and not be so broad as to encompass both qualifying an. non-qualifying facilities. This intent is expressed in subsection (e)(2) of this section.

The conferees intend that the term "transmission facilities of an electric utility" be interpreted broadly.

Section 203. Wheeling

This section amends part II of the Federal Power Act to permit any electric utility to apply to the Commission for an order requiring another electric utility to wheel power to the applicant.

Subsection (a) provides for an application procedure for electric utilities. The application must include notice and an opportunity for an evidentiary hearing. For purposes of providing notice, the conferees intend that the phrase "affected electric utility", as used in this subsection and subsection (b), be interpreted to apply to the two electric utilities which have made the arrangements for the sale of power as well as the utility being requested to wheel the power.

In subsection (a)(2)(B), the conferees intend that the phrase "efficient use of facilities and resources" include the efficient use of both existing facilities and resources and facilities and resources reasonably contemplated to be used in the future. The conferees intend that the term "resources" include capital resources.

Subsection (a) also provides that no order may be issued under subsection (a) unless the Commission determines that the order: (1) is in the public interest; (2) would conserve a significant amount of energy, or significantly promote the efficient use of facilities or resources, or improve the reliability of one or more of the utility systems to which the order applies; and (3) meets the requirements of section 212.

The conferees note that the tests specified in section 210(c)(2) for an interconnection order are not the same as the tests specified in the new section 211(a)(2) for a wheeling order.

Subsection (b) deals with the situation where one electric utility has been requested to provide transmission services to the applicant utility and gives actual or constructive notice that it is unwilling or unable to provide electric service to the applicant utility.

If one utility decides to cut off electric service to another he had previously supplied, the other utility may apply for an order under this subsection as, for example, when the first utility has a contract to cover the power needs of the other utility and decides not to renew the contract thus jeopardizing the second utility's ability to serve its customers.

It is intended that applicants for transmission services be entitled to proceed under either 211(a) or 211(b), or apply under both subsections through pleadings framed in the alternative.

In granting the Commission authority to order a utility to increase its transmission capacity in order to carry out wheeling, the conferees intended the Commission to consider situations for wheeling other than those which solely involved the use of excess capacity. Should a wheeling order involve the use of excess capacity, the Commission, in its order and deliberations, should take into account the financial and technical adjustments which may have to be made in the future by the affected utilities as the excess capacity is absorbed by the growth in transmission requirements.

Subsection (c)(1) stipulates that any order for transmission services under subsection (a) may not be issued unless the Commission finds that such order reasonably preserves existing competitive relationships between the utilities affected by the order. These relationships may involve, in addition to utilities mentioned in the order, utilities serving or seeking to serve the ultimate consumers of the electric energy transmitted pursuant to the order. The conferees do not intend that the Commission order wheeling which significantly alters the competitive relationship among utilities in competition with one another for the same customers. Further, it is not the intention of the conferees that the Commission should be required to maintain or protect in any manner any relationship between utilities which is unlawful under the antitrust laws.

The conferees intend in subsection (c)(2)(B) that the term "amount . . . currently provided" be measured on the effective date of the order under subsection (a) or (b).

Subsection (c)(3) is intended by the conferees to bar wheeling orders for purposes of sale by a utility to an ultimate consumer who is within the service territory of another utility (other than the applicant) where such territory is established by or under State law, rule, or decision.

In subsection (c)(4), the conferees intend that the Commission not issue any order under subsection (a) or (b) to provide transmission of electric energy directly to any ultimate consumers of an electric utility, but that they issue orders, subject to this section, for the transmission of electric energy only among electric utilities.

Subsection (d) provides for a statutory procedure by which a utility ordered to provide transmission services under this section may apply for an order permitting such utility to cease providing all or any portion of such services. The original order may provide for termination procedures.

Subsection (d)(1)(B) contains a means by which a utility may regain transmission capacity which was excess to its needs at the time the wheeling order was issued, but only if the order was predicated on the existence of this excess capacity.

The conferees do not intend that the wheeling authority granted by this section affect the authority of the Commission under other provisions of law to order wheeling for purposes of continuation of service. Orders under this section are not to be used to require utilities to enter into arrangements for buying or selling power, but rather to require a third party to provide transmission services between a willing seller and willing buyer of electric energy.

Section 204. General provisions regarding certain interconnection and wheeling authority

Subsection (a) of this section adds a section 212 to the Federal Power Act. It sets out general terms and conditions which govern issuing orders under sections 210 and 211.

Section 212 prohibits the Commission from issuing an order under section 210 or 211 unless it makes certain findings as to the economic

loss, burden, effects on reliability, and ability to render adequate service, as a result of the order.

The Commission is prohibited from compelling the enlargement of generating facilities for purposes of an order under section 210 or 211.

Section 212 also requires the applicant for an order under section 210 or 211 to demonstrate that he is ready, willing, and able to reimburse the utility subject to the order for various costs incurred by the utility subject to the order. In addition, this provision identifies the procedures that the Commission must follow in the determination of the terms and conditions under which the order will be carried out.

Finally, section 212 provides for limited jurisdiction to the Commission under the Federal Power Act for electric utilities subject to an order under section 210 or 211 of the Act and not otherwise subject to Commission jurisdiction under part II of the act.

The conferees intend that any evidentiary hearing held under new sections 210, 211 or 212 of the Federal Power Act provide an opportunity in such hearing for participation by utilities involved in an interconnection arrangement, the utility being requested to wheel power, the utilities which are or would be the present and the proposed seller and buyer in an arrangement for the sale or exchange of power, and all utilities whose systems, operations, costs or revenues would be affected by the proposed order and arrangements, and customers of such utilities.

Subsection (a)(1) of new section 212 contains a requirement that no order be issued unless the Commission determines, based upon a showing of the parties, that the order is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility, qualifying cogenerator, or qualifying small power producer, affected by the order. The conferees intend that the Commission evaluate (based upon a showing by the party claiming the loss) the likelihood of incurring, either at the time the order is issued, or at any time thereafter, any reasonable ascertainable costs to the party as a result of the order being issued. If such reasonably ascertainable uncompensated economic losses are likely to result, the order shall not be issued. The requirement that a Commission determination be based upon a showing of the parties is not intended to preclude the Commission from considering all the evidence on the proceeding, including material presented by the Commission staff.

Subsection (a)(2) of new section 212 states that no order may be issued unless the Commission determines that the order will not place an undue burden on an electric utility, qualifying cogenerator, or qualifying small power producer affected by the order. The conferees intend that the Commission not consider any loss under paragraph (1) of this subsection as an undue burden under this paragraph because the evaluation under paragraph (1) should take that kind of loss into account.

Subsection (a) also indicates the Commission has no authority under section 210 or 211 to compel enlargement of generating facilities although it may compel the enlargement of transmission capacity.

Subsection (b)(1) provides that no order may be issued under section 210 unless the applicant for such order demonstrates that he is ready, willing and able to reimburse the person subject to the order

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for reasonably anticipated costs incurred under the order. The conferees intend that the phrase "reasonably anticipated costs incurred" include costs of any enlargement of transmission facilities.

It is the intention of the conferees that subsection (b)(2) of section 212 permits the Commission, in appropriate circumstances, to require that in the case of an application for wheeling services where enlargement of transmission capacity is necessary, the applicant must demonstrate that he is ready, willing, and able to reimburse the wheeler for that enlargement prior to the utility subject to the wheeling order undertaking the enlargement. The conferees intend that the Commission will evaluate the costs of transmission services.

Subsection (c) of section 212 sets forth the procedure for reaching agreement on the terms and conditions of the order. Paragraph (1) allows the Commission to disapprove terms and conditions agreed to by the parties. The Commission is to determine a reasonable period of time for these negotiations, based upon its view of the purposes of the order in terms of need for implementation. It is the intention of the conferees that generally the Commission shall not disapprove such terms and conditions unless the Commission determines that they are inconsistent with the applicable provisions of section 210, or 211 and 212 or that they would be detrimental to ratepayers of one or more of the parties.

Subsection (d) provides that when the Commission fails to issue an order for which an application was made, the Commission shall issue an order denying the application. Such denial shall include a statement of the reasons for the denial.

Subsection (e) of new section 212 expresses the intention of the conferees that the authorities granted in sections 210 and 211 are in addition to and not in lieu of other authority the Commission may have under the Federal Power Act.

Subsection (f) of new section 212 deals with the issuance of orders under sections 210 and 211 and the relationship of such orders to one provision of the Tennessee Valley Authority Act. That provision is the third sentence of section 15d(a) of the TVA Act. The limitations contained in that sentence are not superseded by the conference agreement.

After the Commission issues an order under either section 210 or 211 requiring an action by TVA, the order will be stayed for 60 days. During this period, the Commission may initiate a determination whether implementation of the order would violate the third sentence of section 15d(a) of the TVA Act. It shall initiate such a determination if any aggrieved person petitions it to do so within such 60-day period. Once initiated, the Commission must give public notice thereof and promptly make the determination. The conferees intend that any person can appeal the determination of the Commission. The Commission must stay its order until there is a final resolution of the matter in the form of a final determination that no violation exists or until congressional action within the third sentence of 15d(a) of the TVA Act takes effect. Provision is made for judicial review of the determination.

Subsection (h) of section 204 of the conference substitute provides for limited jurisdiction for electric utilities subject to an order under

section 210 or 211 of the Federal Power Act (as added by the conference substitute) and not otherwise subject to jurisdiction under part II of the Federal Power Act.

If a utility, not otherwise subject to the jurisdiction of the Commission is ordered to interconnect or wheel under this section or to make sales or exchanges over a transmission line under this section, only the limited jurisdiction as stated in this subsection would attach to that utility. Any other utility, which is not subject to the jurisdiction of the Commission, and which is connected to the utility ordered to interconnect or wheel would remain free from the Commission's jurisdiction as long as the required interconnection or wheeling is not used in a manner unauthorized by the order.

However, the electric utility ordered to interconnect or wheel and any utility connected to it may become subject to the jurisdiction of the Commission if the utility ordered to interconnect or wheel acts in a manner not authorized by the order and such unauthorized action would be otherwise subject to the jurisdiction of the Commission.

Section 205. Pooling

This section authorizes the Commission on its own motion, and requires the Commission on application, to exempt electric utilities, where the circumstances specified in this section exist, from State laws, rules or regulations that prohibit or prevent voluntary pooling. No exemption is authorized where FERC finds that the law, regulation, or rule is required by Federal law or is designed to protect public health, safety or welfare or the environment or conserve energy or mitigate emergencies resulting from fuel shortages. This prohibition would include State siting laws, regulations under the Clean Air Act, and zoning laws, among others. Second, this section requires an 18-month Commission study on pooling. Third, it authorizes the Commission to recommend to electric utilities that they voluntarily negotiate to establish pooling arrangements where there is an opportunity through such an arrangement to conserve energy, to optimize the efficiency of use of facilities and resources, or to increase reliability.

The conferees do not intend that the authority contained in subsection (a) of this section override any exclusive retail marketing area. It is directed at State laws and rules or regulations thereunder which prohibit or prevent voluntary coordination of electric utilities if the Commission determines, upon its own motion or upon complaint, that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area.

Section 206. Continuance of service

The purpose of this section is to help insure the continuity of service to customers of public utilities. Public utilities are required to promptly report any anticipated shortages which would affect their capability to serve their wholesale customers, to submit contingency plans and to accommodate shortages (or circumstances which may result from such shortages) consistent with the provisions of this section.

The language of this section is a combination of the House and Senate provisions with some modifications.

The phrase in paragraph (3)(A) of subsection (g) "give due consideration to the public health, safety, and welfare" is intended to convey the idea that contingency plans, if implemented, should have a minimum adverse effect on the public health, safety, and welfare.

The conferees understand that proceedings are now pending that relate to the question of priority of service in the event of an outage of electrical service. In adopting the language of this section it is the intention of the conferees that their action will have no influence on the outcome of the pending litigation insofar as existing law is concerned. Furthermore, this section, is not intended to impinge on any emergency authority regarding continuity of service in existing law.

In subsection (g)(2) the conferees intend that the Commission can approve plans submitted thereunder on the basis of the criteria listed in paragraph (3) and require use of these approved plans under paragraph (3). Also the conferees intend that the Commission may require periodic updating of these plans.

Section 207. Consideration of proposed rate increases

This section amends the Federal Power Act to increase the number of days of notice that a public utility must provide to the Commission and to the public prior to such public utility making any change in the rate schedule then in effect. It also requires that the Commission conduct a study of the legal requirements and administrative practices and procedures involved in the consideration of applications for proposed wholesale electric rate increases under the Federal Power Act. The Commission must report to Congress regarding the results of its study within 9 months after the date of enactment.

In adopting subsection (b), the conferees do not intend to imply that the Commission should postpone, until the study mandated in this section is complete, any efforts under existing law to improve the consideration of proposed rate increases.

Section 208. Automatic adjustment clauses

This section amends section 205 of the Federal Power Act to require that, not less often than every 4 years, the Commission make a thorough review of automatic adjustment clauses in public utility rate schedules to examine whether or not each such clause effectively provides incentives for the efficient use of resources (including economical purchase and use of fuel and electric energy) and whether each clause reflects any cost other than those subject to periodic fluctuations and not susceptible to precise determination in rate cases in individual rate proceedings or in separate proceedings. Since this is an amendment to part II of the Federal Power Act, these requirements apply only to the rates of public utilities which rates are subject to the jurisdiction of the Commission as provided in section 201. If a public utility has both nonjurisdictional and jurisdictional rates the amendment would still apply only to the jurisdictional rates of the utility.

Paragraphs (2) and (3) contain additional requirements and powers with respect to the Commission's review of the use of automatic adjustment clauses. Paragraph (4) contains the definition of the term "automatic adjustment clause". The conferees do not indicate any preference for inclusion or exclusion of any item in an automatic adjustment clause.

Section 209. Reliability

The purpose of this section is to require the Secretary of Energy to study ways to improve the reliability of service to electrical consumers, to authorize the Secretary to request appropriate persons to examine and report to him on reliability issues, to authorize the Secretary to recommend to the electric utility industry standards for reliability, and to require that the Secretary, in his annual report, make recommendations concerning reliability of service to electrical consumers.

Section 210. Cogeneration and small power production

Section 210, as agreed to by the conferees, is a compromise of the House and Senate positions on cogeneration and small power production. In lieu of the Senate guideline approach, this section requires that States and utilities follow rules which the Federal Energy Regulatory Commission is to prescribe within one year after the date of enactment of this legislation.

Subsection (a) of this section states that the rules the Commission is required to prescribe under this section require electric utilities to offer to sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and require electric utilities to offer to purchase electric energy from these facilities.

Subsection (a) also contains procedural requirements with respect to the hearings to be conducted prior to final promulgation of the rules and limits the authority of the Commission to authorize in these rules cogeneration facilities or small power production facilities to make any sale for purposes other than resale. The conferees do not intend that this limitation on the Commission's authority will limit the States from allowing such sales to take place. The cogenerator or small power producer may be permitted to make retail sales pursuant to State law.

Subsection (b) of this section deals with the requirements that the Congress places on the Federal Energy Regulatory Commission in prescribing the rules under subsection (a). These rules shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualified cogenerator or qualified small power producer, the rates for this type of purchase are to be just and reasonable to the electric consumers of the utility, in the public interest, and are not to discriminate against cogenerators or small power producers. The conferees intend that the phrase "just and reasonable to the electric consumers of the utility" be interpreted in a manner which looks to protecting the interests of the electric consumer in receiving electric energy at equitable rates. It is not the intention of the conferees that cogenerators and small power producers become subject, by virtue of this language, and the rules promulgated under this section, to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power. The conferees recognize that cogenerators and small power producers are different from electric utilities, not being guaranteed a rate of return on their activities generally or on the activities vis a vis the sale of power to the utility and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable.

The conferees wish to make clear that cogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications, but rather in a less burdensome manner. The establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production.

This subsection further states that the utility would not be required to purchase electric energy from a qualifying cogeneration or small power production facility at a rate which exceeds the lower of the rate described above, namely a rate which is just and reasonable to consumers of the utility, in the public interest, and nondiscriminatory, or the incremental cost of alternate electric energy. This limitation on the rates which may be required in purchasing from a cogenerator or small power producer is meant to act as an upper limit on the price at which utilities can be required under this section to purchase electric energy. The conferees do not intend cogenerators or small power producers to be subject, under the commission's rules, to utility-type regulation.

Subsection (c) deals with the requirements with respect to sales by utilities to cogenerators and small power producers and requires that these rates be just and reasonable and in the public interest and do not discriminate against cogenerators or small power producers. Here the phrase "just and reasonable" is intended to refer to traditional utility ratemaking concepts. The conferees do not intend that the cogenerator or small power producer pay any more or any less than is otherwise just and reasonable in terms of the utility receiving the reasonable rate of return for providing service to those kinds of users. However, unreasonable rate structure impediments, such as unreasonable hook up charges or other discriminatory practices, would not be allowed.

The conferees use the phrase "not discriminate against cogenerators or small power producers" because they were concerned that the electric utility's obligations to purchase and sell under this provision might be circumvented by the charging of unjust and non-cost based rates for power solely to discourage cogeneration or small power production. This phrase should not be construed to permit discrimination against the electric consumers of an electric utility in formulating rates under this provision. The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers.

Subsection (d) deals with the definition of the term "incremental cost of alternative electric energy" as used in the last sentence of subsection (b). This term is defined as the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source. In interpreting the term "incremental cost of alternative energy", the conferees expect that the Commission and the States may look beyond the cost of alternative sources which are instantaneously available to the utility. Rather, the Commission and States should look to the reliability of that power to the utility and the cost savings to the utility which may result at some later date by reason of supply to the utility at that time of power from the cogenerator or small power producer; for example, an electric utility which owns a source of hydroelectric power and which is offered the sale of electric energy from a cogenerator or small power producer might, if measured over the short term, have a low incremental cost of alternative power because of its access to hydropower; however, it may be the case that by purchasing from the cogenerator or small power producer and saving hydropower for later use, the utility can avoid the use of expensive electric energy generated by fossil fired units during later months of its seasonal generation cycle. Thus, viewed over the longer period of time, the incremental cost of alternative electric energy might be substantially higher than that measured by the instantaneously available hydropower.

In providing that the 30-80 megawatt class of small power production facilities may not be exempt from the Federal Power Act under subsection (e), the conferees intended that where such facilities are subject to Federal Power Act jurisdiction, the Commission must set the rates for the sale of power by such facilities in accordance with the requirements of this section.

The conferees expect that the Commission, in judging whether the electric power supplied by the cogenerator or small power producer will replace future power which the utility would otherwise have to generate itself either through existing capacity or additions to capacity or purchase from other sources, will take into account the reliability of the power supplied by the cogenerator or small power producer by reason of any legally enforcible obligation of such cogenerator or small power producer to supply firm power to the utility.

Section 211. Interlocking directorates

This section amends section 305 of the Federal Power Act, by adding a new subsection. The conferees agreed to adopt with some revisions the disclosure provisions contained in the House bill. The provisions in the House bill authorizing the Commission to prohibit an officer or director of a public utility from holding other positions were not adopted. The Senate amendments contained no comparable provision.

In paragraph (2)(D) of this new subsection, the conferees intend that the 20 purchasers of electric energy be measured in terms of electric energy bought from the utility.

The definition of the word "controlled" in paragraph (2)(F) of new subsection (c) is, the conferees intend, to be defined by the Commission. The conferees were reluctant to establish a single arbitrary percentage of stock ownership as the yardstick for measuring control. Rather, it is anticipated that after appropriate consideration, the Commission will arrive at a definition that takes into account the nature and extent of control of one firm by another.

Section 212. Public participation before Federal Energy Regulatory Commission

The House bill contained a provision creating an Office of Public Counsel and provided that the Director of the Office would administer and distribute a fund to compensate certain intervenors unable to afford to participate in proceedings before the Commission. The conferees agreed to adopt this provision with some modification and to require the Director of the Office to coordinate all other assistance provided by the Commission to intervenors in proceedings before the Commission.

The creation of the Office of Public Participation, it should be emphasized, does not relieve the Commission of its obligations under other provisions of law to provide for public participation.

Paragraph (3) states that nothing in this section shall affect or restrict any rights of any participant in any proceeding under any other applicable law or rule of law. Payment of funds pursuant to this section does not permit the Director or the Commission to control the nature of the legal representation or manner of handling of a case in any proceeding. Payment of costs of participation are not intended to be used as a method to dictate who should represent a participant or intervenor.

The conferees intend that nothing in this section affects any authority the Commission may have with respect to providing assistance to the public with regard to matters before the Commission.

Section 213. Conduit hydroelectric facilities

The House bill contained a provision which required the Commission to grant an exemption from any licensing or other requirements of part I of the Federal Power Act for any hydroelectric facilities using the hydroelectric potential of a manmade conduit on non-Federal lands if the installed capacity of the facility is not more than 15 megawatts. Such conduit must be operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity. The Senate provision was identical except that the Commission was given discretion to provide such exemptions.

The conferees agreed to adopt the Senate provision.

At the same time, the conferees intend that the Commission apply expedited licensing procedures to the maximum extent practicable (consistent with applicable law) with respect to facilities which are not exempted from licensing.

The amendment in subsection (c) requires consultation with Federal and State fish and wildlife authorities and inclusion of appropriate terms and conditions in the exemption to prevent loss or damage to fish and wildlife resources.

Subsection (d) provides for enforcement of the requirements of subsection (a).

Section 214. Prior action; effect on other authorities

The conferees agreed to adopt this section so as to ensure that the provisions of title II of this act and any amendments to other laws contained in title II will operate prospectively and will not have a retroactive effect with respect to actions taken by the FERC before the date of enactment of this act. In addition, this section is intended to establish the policy that title II of this act serves to create authorities in addition to those established under other Federal law for the FERC and all other Federal agencies. Title II does not affect any

existing authorities of the Commission or other Federal agencies under any other provision of law except as specifically provided therein.

TITLE III—RETAIL POLICIES FOR NATURAL GAS UTILITIES

Section 301. Purposes; coverage

The conference substitute sets out three purposes for the title on retail policies for natural gas utilities. These are largely drawn from the Senate amendment.

The first purpose relates to conservation of energy supplied by gas utilities. It is a purpose of this title to foster conservation by the ultimate end-user of natural gas.

The second purpose relates to optimization of the efficiency of use of facilities and resources by gas utilities. This purpose is directed at the utility in its use of energy and its facilities. The conferees intend to include capital resources within the meaning of resources. The concept of optimization is intended to include the notion that the most efficient use is made of natural gas facilities.

The third purpose relates to encouraging equitable rates for consumers.

These purposes are independent of one another and not listed in any order of preference or priority.

The conferees intend that it is not necessary that all of these three purposes be achieved for any action to be considered to carry out these purposes. Rather, if any of these purposes are achieved and the others are not negatively impacted, a finding can be made that the purposes of the title are achieved. The coverage provision is similar to the coverage provision for title I, except that the threshold here for gas utilities is 10 billion cubic feet.

Section 302. Definitions

Although the definitions listed in section 3 apply to the provisions of title III, there are some terms that appear exclusively in this title and they are defined in this section.

The definitions in this section are a result of combining the definitions from both the House bill and the Senate amendment with technical and clarifying changes.

Section 303. Adoption of certain standards

The conferees intend that since the provisions of this section are parallel to the provisions of section 113, the explanation contained in this statement with respect to the adoption of standards for electric utilities as provided in section 113 are to apply in the same manner to the adoption of standards for gas utilities as provided in this section (except with respect to references in such explanation to section 121).

Section 304. Special rules for standards

Since the provisions of this section are parallel to the provisions of section 115 relating to the termination of service and advertising standards established under section 115 for electric utilities, the conferees intend that the explanation in this statement concerning such stand-

SEC. 507. DECISION OF THE PRESIDENT.

(a) DECISION CONCERNING APPROVAL OR DISAPPROVAL OF PROPOSED SYSTEMS.—(1) After reviewing all the information submitted to him concerning the various proposed crude oil transportation systems eligible for consideration under this title (including environmental impact statements, comments, reports, recommendations, and other information submitted to him at any time before he makes his decision) and after consulting the Secretaries of Energy, the Interior, and Transportation, the President shall decide which, if any, of such systems shall be approved for the purposes of section 508 (relating to procedures for waiver of law), section 509 (relating to expedited procedures for issuance of permits), section 510 (relating to negotiations with the Government of Canada), and section 511 (relating to judicial review). A decision approving a crude oil transportation system may include such modifications and alterations in such system as the President finds appropriate. The President shall issue his decision within 45 days after receiving recommendations and comments submitted to him under section 505(c), except that the President, for such period as he deems necessary, but not to exceed 60 days, may delay his decision and its issuance if he determines that additional time is otherwise necessary to enable him to make a decision. If the President so delays his decision, he shall promptly notify the House of Representatives and the Senate of such delay and shall submit a full explanation of the basis for such delay.

(2) Any decision made under this subsection approving a system proposed under this title shall include a determination that construction and operation of such system is in the national interest and shall be based upon the criteria specified in subsection (b).

(b) CRITERIA.—(1) The criteria for making a decision under this subsection shall include findings of—

(A) environmental impacts of the proposed systems and the capability of such systems to minimize environmental risks resulting from transportation of crude oil;

(B) the amount of crude oil available to northern tier States and inland States and the projected demand in those States under each of such systems;

(C) transportation costs and delivered prices of crude oil by region under each of such systems;

(D) construction schedules for each of such systems and possibilities for delay in such schedules;

(E) feasibility of financing for each of such systems;

(F) capital and operating costs of each of such systems, including an analysis of the reliability of cost estimates and the risk of cost overruns;

(G) net national economic costs and benefits of each such system;

(H) the extent to which each system complies with the provisions of section 410 of the Act approved November 16, 1973 (87 Stat. 594), commonly known as the Trans-Alaska Pipeline Authorization Act;

(I) the effect of each such system on international relations, including the status and time schedule for any necessary Canadian approvals and plans;

(J) impact upon competition by each system;

(K) degree of safety and efficiency of design and operation of each system;

(L) potential for interruption of deliveries of crude oil from the west coast under each such system;

(M) capacity and cost of expanding such system to transport additional volumes of crude oil in excess of initial system capacity;

(N) national security considerations under each such system;

(O) relationship of each such system to national energy policy; and

(P) such other factors as the President deems appropriate.

(2) The period of time for which such findings shall be made shall be the useful life of the crude oil transportation system involved.

(c) PUBLICATION OF FINDINGS AND DECISION.—The President shall make available to the public at the time of issuance of a decision under this section a written statement setting forth findings with respect to each of the criteria specified in subsection (b) and describing the nature and route of crude oil transportation systems, if any, which are approved in the decision. If the President's decision is to approve a system, such statement shall set forth his reasons for approving such system over other proposed systems (if any) eligible for consideration under this title. Such statement along with notification of such decision shall be published in the Federal Register.

SEC. 508. PROCEDURES FOR WAIVER OF FEDERAL LAW.

(a) WAIVER OF PROVISIONS OF FEDERAL LAW.—The President may identify those provisions of Federal law (including any law or laws regarding the location of a crude oil transportation system but not including any provision of the antitrust laws) which, in the national interest, as determined by the President, should be waived in whole or in part to facilitate construction or operation of any such system approved under section 507 or of the Long Beach-Midland project, and he shall submit any such proposed waiver to both Houses of the Congress. The provisions so identified shall be waived with respect to actions to be taken to construct or operate such system or project only upon enactment of a joint resolution within the first period of 60 calendar days of continuous session of Congress beginning on the date of receipt by the House of Representatives and the Senate of such proposal.

(b) JOINT RESOLUTION.—The resolving clause of the joint resolution referred to in subsection (a) is as follows: "That the House of Representatives and Senate approve the waiver of the provisions of law (———) as proposed by the President, submitted to the Congress on ———, 19 .". The first blank space therein being filled with the citation to the provisions of law proposed to be waived by the President and the second blank space therein being filled with the date on which the President submits his decision to wave such provisions of law to the House of Representatives and the Senate. Rules and procedures for consideration of any such joint resolution shall be governed by section 8 (c) and (d) of the Alaskan Natural Gas Transportation Act, other than paragraph (2) of section 8(d), except that for the purposes of this subsection, the phrase "a waiver of provisions of law" shall be substituted in section 8(d) each place where the phrase "an Alaska natural gas transportation system" appears.

SEC. 509. EXPEDITED PROCEDURES FOR ISSUANCE OF PERMITS: ENFORCEMENT OF RIGHTS-OF-WAY.

(a) EXPEDITED PROCEDURES FOR APPROVED SYSTEMS.—After issuance of a decision by the President approving any crude oil transportation system, all Federal officers and agencies shall expedite, to the maximum

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extent practicable, consistent with applicable provisions of law, all actions necessary to determine whether to issue, administer, or enforce rights-of-way across Federal lands and to issue Federal permits in connection with, or otherwise to authorize, construction and operation of such system. Any such action shall be consistent with applicable provisions of law. After taking any such action, such officer or agency shall publish notification of the taking of such action in the Federal Register.

(b) EXPEDITED PROCEDURES FOR LONG BEACH-MIDLAND PROJECT.—All decisions regarding issuance of Federal permits, rights-of-way, and leases and other Federal authorizations necessary for construction and operation of the Long Beach-Midland project shall be consistent with applicable provisions of Federal law, except that such decisions shall be made within 30 days after the date this title becomes effective. The President may extend the date by which such decisions, under the preceding sentence, are to be made to a date not later than 90 days after the effective date of this title. Notification of the making of such decisions shall be published in the Federal Register. Nothing in this section affects any decision made before the date of the enactment of this title.

(c) LAW GOVERNING RIGHTS-OF-WAY.—Rights-of-way over any Federal land with respect to an approved crude oil transportation system or the Long Beach-Midland project shall be governed by the provisions of section 28 of the Act of February 25, 1920, commonly referred to as the Mineral Leasing Act of 1920 (30 U.S.C. 185), other than subsection (w)(2) of such section.

SEC. 510. NEGOTIATIONS WITH THE GOVERNMENT OF CANADA.

With respect to any crude oil transportation system approved under section 507(a) all or any part of which is to be located in Canada, the President of the United States is authorized and requested to enter into negotiations with the Government of Canada to determine what measures can be taken to expedite the granting of approvals by the Government of Canada for construction or operation of such system, and he is authorized and requested to explore the possibility of further exchanges of crude oil supplies between the United States and Canada.

SEC. 511. JUDICIAL REVIEW.

(a) NOTICE.—The President or any other Federal officer shall cause notice to be published in the Federal Register and in newspapers of general circulation in the areas affected whenever he makes any decision described in subsection (b).

(b) REVIEW OF CERTAIN FEDERAL ACTIONS.—Any action seeking judicial review of an action or decision of the President or any other Federal officer taken or made after the date of the enactment of this Act concerning the approval or disapproval of a crude oil transportation system or the issuance of necessary rights-of-way, permits, leases, and other authorizations for the construction, operation, and maintenance of the Long Beach-Midland project or a crude oil transportation system approved under section 507(a) may only be brought within 60 days after the date on which notification of the action or decision of such officer is published in the Federal Register, or in newspapers of general circulation in the areas affected, whichever is later.

(c) JURISDICTION OF COURTS.—An action under subsection (b) shall be barred unless a petition is filed within the time specified. Any such petition shall be filed in the appropriate United States district court.

A copy of such detition shall be transmitted by the clerk of such court to the Secretary. Notwithstanding the amount in controversy, such court shall have jurisdiction to determine such proceeding in accordance with the procedures hereinafter provided and to provide appropriate relief. No State or local court shall have jurisdiction of any such claim whether in a proceeding instituted before, on, or after the date this title becomes effective. Any such proceeding shall be assigned for hearing at the earliest possible date and shall be expedited by such court. No court shall have jurisdiction to grant any injunctive relief against the issuance of any right-of-way, permit, lease, or other authorization in connection with a crude oil transportation system approved under section 507(a) or the Long Beach-Midland project, except as part of a final judgment entered in a case involving a claim filed pursuant to this section.

SEC. 512. AUTHORIZATION FOR APPROPRIATION.

There are authorized to be appropriated to the Secretary of the Interior to carry out his responsibilities under this title not to exceed $500,000 for the fiscal year ending on September 30, 1978, and not to exceed $1,000,000 for the fiscal year ending on September 30, 1979.

TITLE VI—MISCELLANEOUS PROVISIONS

SEC. 601. STUDY CONCERNING ELECTRIC RATES OF STATE UTILITY AGENCIES.

(a) STUDY AND REPORT.—The Secretary, in consultation with the Commission and appropriate State regulatory authorities and other persons, shall conduct a study concerning the effects of provisions of Federal law on rates established by State utility agencies. The Secretary shall submit a report to Congress containing the results of such study not later than 1 year after the date of the enactment of this Act.

(b) DEFINITION.—The term "State utility agency" means an agency of a State (not including any political subdivision or agency thereof or any public power district) which is an electric utility.

SEC. 602. SEASONAL DIVERSITY ELECTRICITY EXCHANGE.

(a) AUTHORITY.—The Secretary may acquire rights-of-way by purchase, including eminent domain, through North Dakota, South Dakota, and Nebraska for transmission facilities for the seasonal diversity exchange of electric power to and from Canada if he determines—

(1) after opportunity for public hearing—

(A) that the exchange is in the public interest and would further the purposes referred to in section 101 (1) and (2) of this Act and that the acquisition of such rights-of-way and the construction and operation of such transmission facilities for such purposes is otherwise in the public interest,

(B) that a permit has been issued in accordance with subsection (b) for such construction, operation, maintenance, and connection of the facilities at the border for the transmission of electric energy between the United States and Canada as is necessary for such exchange of electric power, and

(C) that each affected State has approved the portion of the transmission route located in such State in accordance with

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applicable State law, or if there is no such applicable State law in such State, the Governor has approved such portion; and

(2) after consultation with the Secretary of the Interior and the heads of other affected Federal agencies, that the Secretary of the Interior and the heads of such other agencies concur in writing in the location of such portion of the transmission facilities as crosses Federal land under the jurisdiction of such Secretary or such other Federal agency, as the case may be.

The Secretary shall provide to any State such cooperation and technical assistance as the State may request and as he determines appropriate in the selection of a transmission route. If the transmission route approved by any State does not appear to be feasible and in the public interest, the Secretary shall encourage such State to review such route and to develop a route that is feasible and in the public interest. Any exercise by the Secretary of the power of eminent domain under this section shall be in accordance with other applicable provisions of Federal law. The Secretary shall provide public notice of his intention to acquire any right-of-way before exercising such power of eminent domain with respect to such right-of-way.

(b) PERMIT.—Notwithstanding any transfer of functions under the first sentence of section 301(b) of the Department of Energy Organization Act, no permit referred to in subsection (a)(1)(B) may be issued unless the Commission has conducted hearings and made the findings required under section 202(e) of the Federal Power Act and under any applicable executive order respecting the construction, operation, maintenance, or connection at the borders of the United States of facilities for the transmission of electric energy between the United States and a foreign country. Any finding of the Commission under an applicable executive order referred to in this subsection shall be treated for purposes of judicial review as an order issued under section 202(e) of the Federal Power Act.

(c) TIMELY ACQUISITION BY OTHER MEANS.—The Secretary may not acquire any rights-of-way under this section unless he determines that the holder or holders of a permit referred to in subsection (a)(1)(B) are unable to acquire such rights-of-way under State condemnation authority, or after reasonable opportunity for negotiation, without unreasonably delaying construction, taking into consideration the impact of such delay on completion of the facilities in a timely fashion.

(d) PAYMENTS BY PERMITTEES.—(1) The property interest acquired by the Secretary under this section (whether by eminent domain or other purchase) shall be transferred by the Secretary to the holder of a permit referred to in subsection (b) if such holder has made payment to the Secretary of the entire costs of the acquisition of such property interest, including administrative costs. The Secretary may accept, and expend, for purposes of such acquisition, amounts from any such person before acquiring a property interest to be transferred to such person under this section.

(2) If no payment is made by a permit holder under paragraph (1), within a reasonable time, the Secretary shall offer such rights-of-way to the original owner for reacquisition at the original price paid by the Secretary. If such original owner refuses to reacquire such property after a reasonable period, the Secretary shall dispose of such property in accordance with applicable provisions of law governing disposal of property of the United States.

(e) FEDERAL LAW GOVERNING FEDERAL LANDS.—This section shall not affect any Federal law governing Federal lands.

(f) REPORTS.—The Secretary shall report annually to the Congress on the actions, if any, taken pursuant to this section.

SEC. 603. UTILITY REGULATORY INSTITUTE.

(a) MATCHING GRANTS.—The Secretary may make grants under this section to an institute established by the National Association of Regulatory Utility Commissioners to enable such institute to—

(1) conduct research on electric and gas utility regulatory policy issues,

(2) develop data processing and retrieval methods for electric and gas utility ratemaking, and

(3) perform other functions directly related to assisting State regulatory authorities in carrying out their functions under State law and this Act.

(b) FEDERAL SHARE.—Grants under this section shall not be used to provide more than the following percentages of the cost to the institute of carrying out the activities specified in subsection (a):

(1) 80 percent for the fiscal year 1979; and

(2) 60 percent for the fiscal year 1980.

The remaining amounts expended by the institute may not be provided from Federal sources.

(c) RESTRICTIONS.—Grants under this section may not be made subject to terms and conditions other than those the Secretary deems necessary for purposes of administering this section and for purposes of assuring that—

(1) all information gathered by the institute is available to the Secretary, the Commission, and the public, and

(2) no portion of any such grant is used to support or oppose any legislative proposal except by means of testimony by representatives of the institute provided by invitation to a committee of Congress or of a State legislature.

(d) AUTHORIZATION OF APPROPRIATIONS.—There is authorized to be appropriated not more than $2,000,000 for each of the fiscal years 1979 and 1980 for purposes of making grants under this section. No amounts may be appropriated for any fiscal year after the fiscal year 1980 to carry out the purposes of this section without a specific authorization of Congress.

SEC. 604. COAL RESEARCH LABORATORIES.

(a) DESIGNATION.—So much of section 801 of the Surface Mining Control and Reclamation Act of 1977 as precedes subsection (b) of paragraph (2) thereof is amended to read as follows:

"ESTABLISHMENT OF UNIVERSITY COAL RESEARCH LABORATORIES

"SEC. 801. (a) The Secretary of Energy, after consultation with the National Academy of Engineering, shall designate thirteen institutions of higher education at which university coal research laboratories will be established and operated. Ten such designations shall be made as provided in subsection (e) and the remaining three shall be made in fiscal year 1980.

"(b) In making designations under this section, the Administrator shall consider the following criteria:

"(1) Those ten institutions of higher education designated as provided in subsection (e) shall be located in a State with abundant coal reserves.".

(b) AUTHORIZATION OF APPROPRIATIONS.—Section 806 of such Act is amended to read as follows:

"AUTHORIZATION OF APPROPRIATIONS

"SEC. 806. (a) For the ten institutions referred to in the last sentence of section 801(a), there are authorized to be appropriated not to exceed $30,000,000 for the fiscal year ending September 30, 1979 (including the cost of construction, equipment, and startup expenses), and not to exceed $7,500,000 for the fiscal year 1980 and for each fiscal year thereafter through the fiscal year ending before October 1, 1984, to carry out the provisions of this title.

"(b) For the three remaining institutions referred to in the last sentence of section 801(a), there are authorized to be appropriated not to exceed $6,500,000 for the fiscal year 1980 (including the cost of construction, equipment, and startup expenses), and not to exceed $2,000,000 for each fiscal year after fiscal year 1980 ending before October 1, 1984, to carry out the provisions of this title.".

(c) CONFORMING AMENDMENT.—Title VIII of such Act is amended by striking out the terms "Administrator" and "Administrator, ERDA" in each place they appear and substituting "Secretary of Energy" in each such place.

SEC. 605. CONSERVED NATURAL GAS.

(a) GENERAL RULE.—(1) For purposes of determining the natural gas entitlement of any local distribution company under any curtailment plan, if the Commission revises any base period established under such plan, the volumes of natural gas which such local distribution company demonstrates—

(A) were sold by the local distribution company, for a priority use immediately before the implementation of conservation measures, and

(B) were conserved by reason of the implementation of such conservation measures,

shall be treated by the Commission following such revision as continuing to be used for the priority use referred to in subparagraph (A).

(2) The Commission shall, by rule, prescribe methods for measurement of volumes of natural gas to which subparagraphs (A) and (B) of paragraph (1) apply.

(b) CONDITIONS, LIMITATIONS, ETC.—Subsection (a) shall not limit or otherwise affect any provision of any curtailment plan, or any other provision of law or regulation, under which natural gas may be diverted or allocated to respond to emergency situations or to protect public health, safety, and welfare.

(c) DEFINITIONS.—For purposes of this section—

(1) The term "conservation measures" means such energy conservation measures, as determined by the Commission, as were implemented after the base period established under the curtailment plan in effect on the date of the enactment of this Act.

(2) The term "local distribution company" means any person engaged in the transportation, or local distribution, of natural gas and the sale of natural gas for ultimate consumption.

(3) The term "curtailment plan" means a plan (including any modification of such plan required by the Natural Gas Policy Act of 1978) in effect under the Natural Gas Act which provides for recognizing and implementing priorities of service during periods of curtailed deliveries.

SEC. 606. VOLUNTARY CONVERSION OF NATURAL GAS USERS TO HEAVY FUEL OIL USERS.

(a) IN GENERAL.—(1) In order to facilitate voluntary conversion of facilities from the use of natural gas to the use of heavy petroleum fuel oil, the Commission shall, by rule, provide a procedure for the approval by the Commission of any transfer to any person described in paragraph 2(B)(i), (ii), or (iii) of contractual interests involving the receipt of natural gas described in paragraph 2(A).

(2)(A) The rule required under paragraph (1) shall apply to—

"(i) natural gas—

(I) received by the user pursuant to a contract entered into before September 1, 1977, not including any renewal or extension thereof entered into on or after such date other than any such extension or renewal pursuant to the exercise by such user of an option to extend or renew such contract;

(II) other than natural gas the sale for resale or the transportation of which was subject to the jurisdiction of the Federal Power Commission under the Natural Gas Act of September 1, 1977;

(III) which was used as a fuel in any facility in existence on September 1, 1977;

(ii) natural gas subject to a prohibition order issued under section 607.

(B) The rule required under paragraph (1) shall permit the transfer of contractual interests—

(i) to any interstate pipeline;

(ii) to any local distribution company served by an interstate pipeline; and

(iii) to any person served by an interstate pipeline for a high priority use by such person.

(3) The rule required under paragraph (1) shall provide that any transfer of contractual interests pursuant to such rule shall be under such terms and conditions as the Commission may prescribe. Such rule shall include a requirement for refund of any consideration, received by the person transferring contractual interests pursuant to such rule, to the extent such consideration exceeds the amount by which the costs actually incurred, during the remainder of the period of the contract with respect to which such contractual interests are transferred, in direct association with the use of heavy petroleum fuel oil as a fuel in the applicable facility exceeds the price under such contract for natural gas, subject to such contract, delivered during such period.

(4) In prescribing the rule required under paragraph (1), and in determining whether to approve any transfer of contractual interests, the Commission shall consider whether such transfer of contractual interests is likely to increase demand for imported refined petroleum products.

(b) COMMISSION APPROVAL.—(1) No transfer of contractual interest authorized by the rule required under subsection (a)(1) may take effect *unless the Commission issues a certificate of public convenience and necessity for such transfer if such natural gas is to be resold by the person to whom such contractual interests are to be transferred. Such certificate shall be issued by the Commission in accordance with the requirements of this subsection and those of section 7 of the Natural Gas Act, and the provisions of such Act applicable to the determination of satisfaction of the public convenience and necessity requirements of such section.*

(2) The rule required under subsection (a)(1) shall set forth guidelines for the application on a regional or national basis (as the Commission determines appropriate) of the criteria specified in subsection (e)(2) and (3) to determine the maximum consideration permitted as just compensation under this section.

(c) Restrictions on Transfers Unenforceable.—Any provision of any contract, which provision prohibits any transfer of any contractual interests thereunder, or any commingling or transportation of natural gas subject to such contract with natural gas the sale for resale or transportation of which is subject to the jurisdiction of the Commission under the Natural Gas Act, or terminates such contract on the basis of any such transfer, commingling, or transportation, shall be unenforceable in any court of the United States and in any court of any State if applied with respect to any transfer approved under the rule required under subsection (a)(1).

(d) Contractual Obligations Unaffected.—The person acquiring contractual interests transferred pursuant to the rule required under subsection (a)(1) shall assume the contractual obligations which the person transferring such contractual interests has under such contract. This section shall not relieve the person transferring such contractual interests from any contractual obligation of such person under such contract if such obligation is not performed by the person acquiring such contractual interests.

(e) Definitions.—For purposes of this section—

(1) The term "natural gas" has the same meaning as provided by section 2(5) of the Natural Gas Act.

(2) The term "just compensation", when used with respect to any contractual interests pursuant to the rule required under subsection (a)(1), means the maximum amount of, or method of determining, consideration which does not exceed the amount by which—

(A) the reasonable costs (not including capital costs) incurred, during the remainder of the period of the contract with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1), in direct association with the use of heavy petroleum fuel oil as a fuel in the applicable facility, exceeds

(B) the price under such contract for natural gas, subject to such contract, delivered during such period.

For purposes of subparagraph (A), the reasonable costs directly associated with the use of heavy petroleum fuel oil as a fuel shall include an allowance for the amortization, over the remaining useful life, of the undepreciated value of depreciable assets located on the premises containing such facility, which assets were directly associated with the use of natural gas and are not usable in connection with the use of such heavy petroleum fuel oil.

(3) The term "just compensation", when used with respec[illegible] any intrastate pipeline which would have transported or distributed natural gas with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1), means an amount equal to any loss of revenue, during the remaining period of the contract with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1), to the extent such loss—

(A) is directly incurred by reason of the discontinuation of the transportation or distribution of natural gas resulting from the transfer of contractual interests pursuant to the rule required under subsection (a)(1); and

(B) is not offset by—

(i) a reduction in expenses associated with such discontinuation; and

(ii) revenues derived from other transportation or distribution which would not have occurred if such contractual interests had not been transferred.

(4) The term "contractual interests" means the right to receive natural gas under contract as affected by an applicable curtailment plan filed with the Commission or the appropriate State regulatory authority.

(5) The term "interstate pipeline" means any person engaged in natural gas transportation subject to the jurisdiction of the Commission under the Natural Gas Act.

(6) The term "high-priority use" means any use of natural gas (other than its use for the generation of steam for industrial purposes or electricity) identified by the Commission as a high priority use for which the Commission determines a substitute fuel is not reasonably available.

(7) The term "heavy petroleum fuel oil" means number 4, 5, or 6 fuel oil which is domestically refined.

(8) The term "local distribution company" means any person, other than any intrastate pipeline or any interstate pipeline, engaged in the transportation, or local distribution, of natural gas and the sale of natural gas for ultimate consumption.

(9) The term "intrastate pipeline" means any person engaged in natural gas transportation (not including gathering) which is not subject to the jurisdiction of the Commission under the Natural Gas Act.

(10) The term "facility" means any electric powerplant, or major fuel burning installation, as such terms are defined in the Powerplant and Industrial Fuel Use Act of 1978.

(11) The term "curtailment plan" means a plan (including any modification of such plan required by the Natural Gas Policy Act of 1978), in effect under the Natural Gas Act or State law, which provides for recognizing and implementing priorities of service during periods of curtailed deliveries by any local distribution company, intrastate pipeline, or interstate pipeline.

(12) The term "interstate commerce" has the same meaning as such term has under the Natural Gas Act.

(f) Coordination With the Natural Gas Act.—(1) Consideration in any transfer of contractual interests pursuant to the rule required

under subsection (a)(1) of this section shall be deemed just and reasonable for purposes of sections 4 and 5 of the Natural Gas Act if such consideration does not exceed just compensation.

(2) No person shall be subject to the jurisdiction of the Commission under the Natural Gas Act as a natural gas-company (within the meaning of such Act) or to regulation as a common carrier under any provision of Federal or State law solely by reason of making any sale, or engaging in any transportation, of natural gas with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1).

(3) Nothing in this section shall exempt from the jurisdiction of the Commission under the Natural Gas Act any transportation in interstate commerce of natural gas, any sale in interstate commerce for resale of natural gas, or any person engaged in such transportation or such sale to the extent such transportation, sale, or person is subject to the jurisdiction of the Commission under such Act without regard to the transfer of contractual interests pursuant to the rule required under subsection (a)(1).

(4) Nothing in this section shall exempt any person from any obligation to obtain a certificate of public convenience and necessity for the sale in interstate commerce for resale or the transportation in interstate commerce of natural gas with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1).

(g) VOLUME LIMITATION.—No supplier of natural gas under any contract, with respect to which contractual interests have been transferred pursuant to the rule required under subsection (a)(1), shall be required to supply natural gas during any relevant period in volume amounts which exceed the lesser of—

(1) the volume determined by reference to the maximum delivery obligations specified in such contract;

(2) the volume which such supplier would have been required to supply, under the curtailment plan in effect for such supplier, to the person, who transferred contractual interests pursuant to the rule required under subsection (a)(1), if no such transfer had occurred; and

(3) the volume actually delivered or for which payment would have been made pursuant to such contract during the 12-calendar-month period ending immediately before such transfer of contractual interests.

SEC. 607. EMERGENCY CONVERSION OF UTILITIES AND OTHER FACILITIES.

(a) PRESIDENTIAL DECLARATION.—The President may declare a natural gas supply emergency (or extend a previously declared emergency) if he finds that—

(1) a severe natural gas shortage, endangering the supply of natural gas for high-priority uses, exists or is imminent in the United States or in any region thereof; and

(2) the exercise of authorities under this section is reasonably necessary, having exhausted other alternatives (not including section 303 of the Natural Gas Policy Act of 1978) to the maximum extent practicable, to assist in meeting natural gas requirements for such high-priority uses.

(b) LIMITATION.—(1) Any declaration of a natural gas supply emergency (or extension thereof) under subsection (a), shall terminate at the earlier of—

(A) the date on which the President finds that any shortage described in subsection (a) does not exist or is not imminent; or

(B) 120 days after the date of such declaration of emergency (or extension thereof).

(2) Nothing in this subsection shall prohibit the President from extending, under subsection (a), any emergency (or extension thereof), previously declared under subsection (a), upon the expiration of such declaration of emergency (or extension thereof) under paragraph (1)(B).

(c) PROHIBITIONS.—During a natural gas emergency declared under this section, the President may, by order, prohibit the burning of natural gas by any electric powerplant or major fuel-burning installation if the President determines that—

(1) such powerplant or installation had on September 1, 1977 (or at any time thereafter) the capability to burn petroleum products without damage to its facilities or equipment and without interference with operational requirements;

(2) significant quantities of natural gas which would otherwise be burned by such powerplant or installation could be made available before the termination of such emergency to any person served by an interstate pipeline for use by such person in a high-priority use; and

(3) petroleum products will be available for use by such powerplant or installation throughout the period the order is in effect.

(d) LIMITATIONS.—The President may specify in any order issued under this section the periods of time during which such order will be in effect and the quantity (or rate of use) of natural gas that may be burned by an electric powerplant or major fuel-burning installation during such period, including the burning of natural gas by an electric powerplant to meet peak load requirements. No such order may continue in effect after the termination or expiration of such natural gas supply emergency.

(e) EXEMPTION FOR SECONDARY USES.—The President shall exempt from any order issued under this section the burning of natural gas for the necessary processes of ignition, startup, testing, and flame stabilization by any electric powerplant or major fuel-burning installation.

(f) EXEMPTION FOR AIR-QUALITY EMERGENCIES.—The President shall exempt any electric powerplant or major fuel-burning installation, in whole or in part, from any order issued under this section for such period and to such extent as the President determines necessary to alleviate any imminent and substantial endangerment to the health of persons within the meaning of section 303 of the Clean Air Act.

(g) LIMITATION ON INJUNCTIVE RELIEF.—(1) Except as provided in paragraph (2), no court shall have jurisdiction to grant any injunctive relief to stay or defer the implementation of any order issued under this section unless such relief is in connection with a final judgment entered with respect to such order.

(2)(A) On the petition of any person aggrieved by an order issued under this section, the United States District Court for the District of Columbia may, after an opportunity for a hearing before such court and on an *appropriate showing, issue a preliminary injunction temporarily enjoining, in whole or in part, the implementation of such order.*

(B) For purposes of this paragraph, subpenas for witnesses who are required to attend the District Court for the District of Columbia may be served in any judicial district of the United States, except that no writ of subpena under the authority of this section shall issue for witnesses outside of the District of Columbia at a greater distance than 100 miles from the place of holding court unless the permission of the District Court for the District of Columbia has been granted after proper application and cause shown.

(h) Definitions.—For purposes of this section—

(1) The terms "electric powerplant", "powerplant", "major fuel-burning installation", and "installation" shall have the same meanings as such terms have under section 103 of the Powerplant and Industrial Fuel Use Act of 1978.

(2) The term "petroleum products" means crude oil, or any product derived from crude oil other than propane.

(3) The term "high priority use" means any—

(A) use of natural gas in a residence;

(B) use of natural gas in a commercial establishment in amounts less than 50 Mcf on a peak day; or

(C) any use of natural gas the curtailment of which the President determines would endanger life, health, or maintenance of physical property.

(4) The term "Mcf", when used with respect to natural gas, means 1,000 cubic feet of natural gas measured at a pressure of 14.73 pounds per square inch (absolute) and a temperature of 60 degrees Fahrenheit.

(i) Use of certain terms.—in applying the provisions of this section in the case of natural gas subject to a prohibition order issued under this section, the term "petroleum products" (as defined in subsection (h)(2) of this section) shall be substituted for the term "heavy petroleum fuel oil" (as defined in section 606(e)(7)) if the person subject to any order under this section demonstrates to the Commission that the acquisition and use of heavy petroleum fuel oil is not technically or economically feasible.

And the Senate agree to the same.

SEC. 608. NATURAL GAS TRANSPORTATION POLICIES.

(a) In General.—Section 7(c) of the Natural Gas Act (15 U.S.C 717f(c)) is amended by adding at the end thereof the following:

"(2) The Commission may issue a certificate of public convenience and necessity to a natural-gas company for the transportation in interstate commerce of natural gas used by any person for one or more high-priority uses, as defined, by rule, by the Commission, in the case of—

"(A) natural gas sold by the producer to such person; and

"(B) natural gas produced by such person.".

(b) Conforming Amendment.—(1) Subsection (c) of section 7 of the Natural Gas Act (15 U.S.C. 717f(c)) is amended—

(A) by striking out "(c)" and inserting in lieu thereof "(c)(1)(A)", and

(B) by inserting "(B)" immediately before "In all other cases" where such term appears in the second undesignated paragraph of such subsection.

(2) Subsection (e) of section 7 of the Natural Gas Act (15 U.S.C. 717f(d)) is amended by striking out "subsection (c)" and inserting in lieu thereof "subsection (c)(1)".

Henry M. Jackson,
J. Bennett Johnston,
John A. Durkin,
Floyd K. Haskell,
Dale Bumpers,
Howard M. Metzenbaum,
James A. McClure,
Pete V. Domenici,
Managers on the Part of the Senate.

Harley O. Staggers,
Thomas L. Ashley,
Al Ullman,
Richard Bolling,
Thomas S. Foley,
John D. Dingell,
Paul G. Rogers,
Bob Eckhardt,
Philip R. Sharp,
Anthony Moffett,
Henry S. Reuss,
James C. Corman,
Charles B. Rangel,
Managers on the Part of the House.

JOINT EXPLANATORY STATEMENT OF THE COMMITTEE OF CONFERENCE

The managers on the part of the House and Senate at the conference on the disagreeing votes of the two Houses on the amendment of the House to the amendment of the Senate to the bill (H.R. 4018) entitled "An Act to suspend until the close of June 30, 1980, the duty on certain doxorubicin hydrochloride antibiotics" submit the following joint statement to the House and Senate in explanation of the effect of the action agreed upon by the managers and recommended in the acompanying conference report:

The Senate amendment to the text of the House bill (H.R. 4018) struck out all of the bill after the enacting clause and inserted a substitute text which contained two titles. Title I (the "Public Utilities Regulatory Polices Act of 1977") contained the taxt of S. 2114, as amended by the Senate. Title II was identical, except for clerical and conforming changes, to part V (Public Utility Regulatory Policies) of title I of H.R. 8444, as passed by the House.

The House amendment to the Senate amendment struck out the text of the Senate amendment and substituted the text of title I of H.R. 8444 as passed by the House.

The Senate recedes from its disagreement to the amendment of the House with an amendment which is a substitute for both the Senate amendment and the House amendment. The differences between the Senate amendment, the House amendment, and the substitute agreed to in conference are noted below, except for clerical correction, conforming changes made necessary by agreements reached by the conferees, and minor drafting and clarifying changes.

Since the Senate and House amendments both substituted new texts for the House bill, H.R. 4018 (which was unrelated to electric and gas utility matters when it originally passed the House), references in the explanation below to "the House bill" are not intended to serve as references to H.R. 4018 as originally passed by the House but as references to Part V of title I of H.R. 8444 as passed by the House. Similarly, since the Senate amendment contained both the texts of S. 2114 as amended by the Senate and the text of Part V of title I of H.R. 8444, as passed by the House, references to the Senate amendment in the explanation below are intended to serve as references to S. 2114 as passed by the Senate.

No action was taken by the conferees with respect to that portion (title II) of the Senate amendment which contained the text of Part V of title I of H.R. 8444 or with respect to that portion of the House amendment to the Senate amendment as contained in other titles of H.R. 8444.

House bill

The House bill contained provisions designed to encourage the conservation of resources by electric utilities and to carry out other purposes by means of establishing national minimum retail electric rate design standards and policies, by adding to the authority of the Federal Energy Regulatory Commission to prescribe rules and procedures regarding the improving of efficiency of, and preserving competition in, generation and transmission of electricity at the wholesale level, by authorizing the Department of Energy to make certain grants to assist the States and by authorizing the Commission to make loans and grants to develop the hydroelectric potential of existing dams which are not being used to generate electric power. In addition, it required the Commission to undertake a study of natural gas retail rate design and imposed certain limited requirements on natural gas utilities.

There were six chapters in the House bill. Chapter 1 set forth the purposes of the House bill including the need to establish national retail electric rate design policies in order to assure that States which would implement rate reforms would not be placed at a competitive economic disadvantage by reason of rates in other States which subsidize certain classes of users.

In chapter 2, the House bill imposed a number of requirements on regulated and nonregulated electric utilities above a certain size after 2 years from the date of enactment. Requirements regarding retail rate design included provisions that rates must be designed to reflect costs of service and be on a time of day and seasonal basis except where not cost-effective. Notwithstanding the requirement that rates reflect cost of service, a State could establish lower than cost rates for the essential electric energy needs of residential class electric customers. Also, individual customers could obtain limited exceptions to these provisions upon a showing of significant economic hardship. There were also provisions requiring the gathering of certain information, prohibiting the recovery by the electric utility from its electric consumers of certain advertising expenses, provisions governing the use of automatic adjustment clauses, and requirements regarding the establishment of nondiscriminatory rates for small electric systems, implementation of load management techniques, transmittal of information to electric consumers, and procedures for termination of electric service.

Chapter 2 of the House bill imposed a compliance determination role on State regulatory authorities and a role for the Commission. It also required State regulatory authorities to prescribe methods for the determination of costs of services and to consider load management techniques. Provision was made for the reimbursement of intervenors in regulatory proceedings and for enforcement and judicial review of utility compliance with chapter 2 in State and Federal court.

Chapter 3 of the House bill expanded the authority of the Federal Energy Regulatory Commission to order interconnections between electric utilities and to order the wheeling of electric power to utilities and pooling among utilities. Chapter 3 also required the Commission to issue rules to insure continuance of service, to establish electric utility reliability standards, and, to facilitate the sale and purchase of electricity between electric utilities and cogeneration facilities. In addition, it contained requirements regarding Commission consideration of proposed new rate schedules. Finally, chapter 3 established

requirements governing the use of automatic adjustment clauses in wholesale sales of electric power and amended restrictions in the Federal Power Act governing interlocking directorates.

Chapter 4 provided for the establishment of a grant program to improve staffing for State regulatory authorities, extended already existing authority to fund innovative rate structures and established a grant program to assist intervenors before State regulatory authorities. In addition, it authorized the establishment in the Commission of an Office of Public Counsel with standing to become a party in any proceeding, and to petition the Commission to seek judicial review of Commission actions.

Chapter 5 required the Commission to undertake a 1-year study of gas utility ratemaking so as to address the effect of incremental and marginal cost pricing, wellhead pricing and declining block gas rates, among other things, on such factors as pipeline and distribution company load factors and demand for and consumption of natural gas. In addition, the chapter established standards regarding the recovery of advertising expenses from consumers and procedures for termination of service, and set forth procedures similar to those in chapter 2 relating to the role of the State regulatory authority and Commission with respect to compliance determination and enforcement.

Chapter 6 established a 3-year program of grants and loans to encourage municipalities, cooperatives, industrial development agencies, and other nonprofit organizations to develop the hydroelectric potential of existing dams at which no such potential is currently in use.

Senate amendment

The Senate amendment set forth three broad national purposes and an additional three purposes related to lifeline rates which were to be advocated by the Secretary of Energy through intervention as a party in ratemaking proceedings before State regulatory authorities and, where no appropriate proceedings for intervention are available, through the submission of written recommendations to nonregulated utilities. The three broad purposes were to encourage overall energy conservation in electric and gas utility systems, to encourage the efficient use of utility facilities and resources, and to encourage equitable ratemaking.

As part of such intervention the Secretary was to examine the utility's methods of determining costs of service and the extent to which the purposes of the Senate amendment might be advanced by the application of rates based on cost of service; by the elimination of declining block rates; by the implementation of time of day rates, load management systems, seasonal rates or special rates for interruptible service.

Furthermore, the Senate amendment provided funding to States for offices of consumer services to assist consumers in their presentations before utility regulatory commissions.

The legislation also required utilities, during the next three years, to adopt so-called "lifeline" rates for subsistence quantities of electricity provided to certain classes of elderly consumers. The level of these rates was to be no more than the lowest rate offered by the utility to any other electric consumer.

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The Senate amendment required State regulatory authorities and nonregulated utilities to furnish bi-annually any available information which the Secretary determined to be necessary to ascertain the costs related to providing electric and natural gas service. If the information was not available, the Secretary could direct the utility or authority to gather the information, if the Secretary reimbursed them for the cost of such gathering.

The utilities covered by the information provisions of the legislation included only those over a certain size.

The Senate amendment had a provision whereby the Federal Energy Regulatory Commission could order utilities to interconnect if certain conditions were met. There were also provisions regarding Commission authority with respect to continuance of service, including requirements that regulated electric utilities report anticipated shortages of electric energy and submit contingency plans to the Commission.

In the case of natural gas utility rate design, the amendment directed that the Department of Energy conduct a 1-year study to examine the relationship of various pricing policies to patterns of consumption and demand and other variables. On the basis of this study, the Secretary of Energy would develop proposals to improve gas utility rate design and to encourage conservation of natural gas.

The Secretary also was required to report to Congress on the implementation of his responsibilities under the Act, on the status of ratemaking and load management practices in the States, on his recommendations for further Federal action, the financial impact of the Act on State regulatory authorities, and on the most cost effective methods of increasing electrical system reliability.

The legislation had provisions which encouraged the development and use of these power sources through the establishment of regulatory guidelines, through exemption from certain Federal requirements, and through a loan guarantee program for development of small hydroelectric facilities.

Finally, the Senate amendment contained certain miscellaneous provisions dealing with the following: grants to the National Regulatory Research Institute, the granting of Federal eminent domain for an electrical transmission line through North Dakota, South Dakota, and Nebraska, natural gas transportation policies, and other policies with respect to natural gas, the construction of oil pipelines in the western part of the United States, a study of "pancaking" of successive requests to the Commission for wholesale electric rate increases, and other miscellaneous provisions.

Conference substitute

The conference substitute is divided into six separate titles as follows:

Title I—Retail Regulatory Policies for Electric Utilities
Title II—Certain Federal Energy Regulatory Commission and Department of Energy Authorities
Title III—Retail Policies for Natural Gas Utilities
Title IV—Small Hydroelectric Power Projects
Title V—Crude Oil Transportation Systems
Title VI—Miscellaneous Provisions.

Section 1. Short title and table of contents

The first section of the conference substitute contains the short title and table of contents.

Section 2. Findings

Section 2 relates to Congressional findings. The conference substitute, as did parts of both the House bill and the Senate amendment, affects certain activities which have traditionally been subject to primary regulation by the States.

Parts of the conference substitute establish procedures and requirements applicable to State utility commissions and to electric and natural gas utilities, and to certain Federal agencies, in the consideration of retail utility rates by such commissions, utilities, and agencies. The conference substitute does not change the primary responsibility of the States with respect to electric utility rates, but it places certain Federal responsibilities and obligations on the State commissions in the exercise of their responsibilities and on utilities within the States which are not otherwise regulated by State commissions.

This section states that the Congress finds that the protection of public health, safety, and welfare, the preservation of national security, and the proper exercise of its authority under the Constitution to regulate interstate commerce and matters affecting interstate commerce, require the Federal program set forth in title I which imposes certain obligations on State regulatory commissions and gives certain rights to persons to go before State regulatory commissions and courts. The Congress also finds for the same reasons that programs are required to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of applications for changes in wholesale rates, and the participation of the public in matters before the Federal Energy Regulatory Commission relating to electric utilities. Section 2 also states that for the same reasons programs are required to provide other measures for the regulation of the wholesale sale of electric energy, to assist in the expeditious development of hydroelectric potential at existing small dams to provide needed hydroelectric power, to provide for the conservation of natural gas, while assuring that rates to natural gas consumers are equitable, and to encourage the development of certain crude oil transportation systems and to create certain other authorities as contained in title VI of the conference substitute.

Section 3. Definitions

Section 3 contains the definitions used in the conference substitute. The definitions in this section are a result of combining the definitions from both the House bill and the Senate amendment with technical and clarifying changes.

With respect to the definition of the term "class", the conferees intend that State commissions, nonregulated utilities, and, on review, the courts, in determining what constitutes similar characteristics of energy use for purposes of this definition, are to base such determinations on factors relating to the nature of the requirements, such as the voltage level, the amount of peak kilowatt demand, and kilowatt-hour demand, placed on the system of the electric utility by a group of consumers and to consider the time at which such peak demand occurs.

Thus, the characteristics of a class are to be determined essentially in terms of the characteristics of energy consumption at the electric consumer's electric meter.

The term "electric utility" includes State and Federal power marketing agencies and the Tennessee Valley Authority. This definition does not apply to the provisions of title II which amend the Federal Power Act. For purposes of these amendments, different definitions are provided in section 201.

With respect to the definition of the term "load management technique", the conferees intend that the words in the definition "to reduce maximum kilowatt demand on the electric utility" are to be interpreted broadly to include reductions in any high demand point in the utility's load curve, and not be interpreted narrowly as applying only to the reduction of demand at the utility's highest peak on the load curve. The language from the House bill relating to maximum kilowatt demand of an electric consumer has been deleted in the conference substitute. The conferees feel that reduction of peak demand on the system is the most important focus for load management techniques and reduction of individual consumer peak demand may or may not coincide with the utility's peak demand periods.

With respect to the definition of the term "sale", the conferees intend that it cover any charge for purchase of electric energy, including an exchange of electric energy.

Section 4. Relationship to antitrust laws

Section 4 of the conference substitute sets forth a disclaimer to the effect that Federal and State antitrust laws are not affected by the conference substitute and such laws will continue to apply to electric and gas utilities to the same extent as prior to enactment of this substitute. Similarly the section contains a disclaimer to the effect, that the authority of the Secretary of Energy and the Commission under other provisions of law respecting unfair methods of competition or anticompetitive acts or practices is not affected. The conferees intend that the provisions of the conference substitute be strictly neutral and not add or subtract from the immunities and defenses available under such laws nor add or subtract from authorities contained in such laws.

The conferees intend to preserve the jurisdiction of the Federal and State courts in actions under antitrust laws, whether or not the parties to such actions could have sought remedies under this legislation.

Specifically with regard to certain authorities to order interconnections and wheeling under title II, it is not intended that the courts defer actions arising under the antitrust laws pending a resolution of such matters by the Federal Energy Regulatory Commission. The conferees specifically intend to preserve jurisdiction of Federal and State courts to resolve, independent of the Commission, such actions, including for example, cases where a refusal to wheel electric energy is alleged to be in violation of such laws. The court should be able to act whether or not action by the Commission under the provisions in title II can be requested or would be justified. In this way, the courts have jurisdiction to proceed with antitrust cases without deferring to the Commission for the exercise of primary jurisdiction.

TITLE I—RETAIL REGULATORY POLICIES FOR ELECTRIC UTILITIES

Subtitle A—General Provisions

Section 101. Purposes

The conference substitute sets out three purposes for the title on retail electric utility rate reform. These are largely drawn from the Senate amendment.

The first purpose relates to conservation of energy supplied by electric utilities. It is a purpose of this title to foster conservation by the ultimate end-user of electricity.

The second purpose relates to optimization of the efficiency of use of facilities and resources by electric utilities. This purpose is directed at the utility in its use of energy and of its facilities. The conferees intend to include capital resources within the meaning of resources. The concept of optimization is intended to include the notion that the most efficient use is made of electric generating and related facilities. Also, the phrase "efficiency of use of . . . resources" is intended to include the concept of conserving scarce energy resources by techniques of rate reform which substitute the use of more plentiful resources produced in the United States in lieu of less plentiful resources, especially those imported into this country.

The third purpose relates to encouraging equitable rates for consumers.

These purposes are independent of one another and not listed in any order of preference or priority.

The conferees intend that it is not necessary that all of these three purposes be achieved for any action to be considered as carrying out these purposes. Rather, if any of these purposes is achieved and the others are not negatively impacted, a finding can be made that the purposes of the title are carried out.

Section 102. Coverage

For purposes of determining which utilities are covered by this title, subsection (a) of this section provides a measurement of total retail sales of electric utilities in a baseline year. If such retail sales are more than 500 million kilowatt-hours in the baseline year, the utility is covered. The baseline year is two years before the year in question, but no year beginning before January 1, 1976, is to be used as a baseline year. Subsection (b) indicates that the requirements of this title apply only to those operations and proceedings of an electric utility that relate to retail sales of electric energy. Operations and proceedings relating to wholesale sales of electric energy by a covered utility which has both wholesale and retail operations are thus not covered by this title.

Subsection (c) is intended to reduce uncertainty as to which specific utilities are covered under this title. The requirement that each State regulatory authority notify the Secretary as to the utilities over which it has ratemaking authority is intended to distinguish the regulated electric utilities from the nonregulated electric utilities, as the requirements of this title are somewhat different for these two kinds of electric utilities. It should be stressed that the list is informational and for

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the convenience of the public, but it is not intended in any way to affect the legal obligations of any utility, or State regulatory commission with regard to any utility, to comply with the provisions of this title if their sales are in fact over the 500 million kilowatt-hour amount specified in subsection (a), even though the utility is not included on the list. On the other hand, if its sales are, in fact, at or under such 500 million kilowatt-hour amount, although included on such list, the utility is not to be covered.

In some instances electric utilities purchase power at wholesale for resale to their customers and consume small quantities of this purchased electric power for their own needs incidental to operation of their own facilities. Arguably, because this power is consumed directly by the purchaser and is not resold prior to consumption, it therefore is obtained by the utility in a retail sale, not as part of the wholesale sale. This argument leads to the result of having what the conferees understand to be a relatively small portion of the sale treated as a retail sale under this Act whereas the balance of power sold is treated as a wholesale sale. The conferees expect the Secretary to review this situation and determine the extent to which consumption by utilities actually occurs and the extent to which such use affects the coverage requirements of section 102(a).

Section 103. Federal contracts

The purpose of this section is to ensure that where a Federal agency is making wholesale sales of electric energy to an electric utility, any contract entered into or renewed after the date of enactment between these parties will not prevent the implementation of any requirement of subtitle B or C, regardless of the fact that (because of section 102(b)) such wholesale sales would not otherwise be covered by the title.

Subtitle B—Standards for Electric Utilities

Section 111. Consideration and determination respecting certain ratemaking standards

Subsection (a) of this section requires each State regulatory authority, on a utility-by-utility basis, and each covered utility not subject to regulation by a State regulatory authority to consider each standard established by this section. The conferees intend that this consideration will focus on how implementation of each standard would affect each utility and its consumers in terms of the three purposes set forth in section 101. For example, would the implementation aid energy conservation by consumers? Would it help the utility optimize the efficient use of resources and facilities? Would it provide equity to ratepayers?

The State regulatory authority or nonregulated utilities would be required, under subsection (a), to make a specific determination whether implementation of the standard is appropriate to carry out the purposes of the title.

The conferees wish to emphasize that under the last sentence of subsection (a) it is provided that for purposes of consideration and determination in accordance with subsections (b) and (c), and for purposes of any review of the consideration and determination in any court, the purposes of this title supplement State law. The con-

ferees intend that these purposes supplement, but do not override State law.

The conferees wish to emphasize that for purposes of consideration and determination in accordance with section 111(b) and (c) and for the purposes of any review of the consideration and determination in any court, the purposes of this title supplement State law.

It should be noted that the test of consistency with State law, as described in section 111(c)(1) is with respect to State law alone and not with respect to State law as supplemented by the 3 purposes of the title. The intent here is that where a State regulatory authority or nonregulated utility finds insufficient authority, pursuant to otherwise applicable State law, under which it may adopt a standard established in section 111, then these three purposes of the title provide such authority. In effect the three purposes expand the discretion of the State regulatory authority or nonregulated utility to adopt the standards of section 111. However, the conferees also intend that 3 purposes do not override State law.

The last sentence of section 111(a) states that nothing in this subsection prohibits any State regulatory authority or nonregulated utility from making the determination that it is not appropriate to implement any such standard pursuant to its authority under otherwise applicable State law. The intention here is to preserve the discretion of the State regulatory authorities and nonregulated utilities which is provided by State law, except to the extent this title imposes procedural requirements such as requirements to hold a hearing, consider and make a determination.

Thus, in making its determination under section 111, the State regulatory authority or nonregulated electric utility may consider, in addition to the 3 purposes of this title, any other factors which State law would permit for consideration in the proceeding.

For example, if the State constitution or State law affords the State regulatory authority or nonregulated utility broad discretion to consider any factors, as documented in the hearing record, that they deem appropriate, then those factors may serve as a basis for the decision of the State regulatory authority or nonregulated utility, either to adopt any standard under this title or to reject it.

Subsection (b)(1) requires that the State authority, or nonregulated utility, in considering each standard, provide a public hearing, after adequate public notice, and make their determination in writing. Such determination must include written findings and be based on the evidence established in the hearing. Copies of such determination must be available to the public.

Subsection (b)(2) generally requires that such consideration and determination must be made in accordance with procedures established by the State authority or nonregulated utility. However, the subsection identifies specific procedural provisions of the conference substitute which supplement the procedures of the State regulatory authority or nonregulated electric utility and which, if State procedural law is in conflict with these provisions, override State procedural law to the extent of such conflict. The conferees intend that the procedural features of the process of consideration and determination, including such concepts as the nature of evidence and the relationship, if any, between findings and the record of a proceeding, be governed by State law. State law governs on such matters as burden of proof, standard for review in State courts, and in any other matters not inconsistent with the requirements of this title.

In requiring that proceedings be held by State regulatory authorities and certain nonregulated utilities, the conferees do not mean to imply that these entities must institute new procedures to comply with this title. Existing procedures may be adequate for this purpose if such procedures are consistent with the requirements of this title.

The conferees understand that many of the issues which will be raised at the State level by reason of the requirements of this legislation will be common to more than one utility under the jurisdiction of a single State regulatory authority. Furthermore, it is recognized that the State regulatory authority may wish to separate consideration of these issues from rate case proceedings at which revenue questions are settled. The conference agreement permits rate structure proceedings which apply either to an individual utility or to more than one utility. These proceedings, either individual or generic, may be distinct from specific rate cases. However, the conferees expect that (1) the results of the rate structure proceedings will apply fully to rate cases, (2) the hearings will be held within the time limits specified within the title, (3) the standards will be examined on a utility-by-utility basis, (4) separate determinations will be made for each utility and each standard, (5) the appellate process for these proceedings will be consistent with that otherwise provided for in the conference substitute, (6) and the rights and privileges of all parties including intervenors will be the same as those in rate cases and will otherwise meet the requirements of this legislation.

Subsection (c) states that the State regulatory authority or nonregulated electric utility may, to the extent consistent with State law, implement any standard determined to be appropriate to carry out the purposes of title or decline to implement any such standard.

The State regulatory authority (or nonregulated utility) could determine the particular standard appropriate to carry out the purposes of section 101 when applied to the particular utility and that such implementation is consistent with otherwise applicable State law. In such case, the State regulatory authority or utility would be authorized by Federal law to implement the standard. Failure to implement such standard would not constitute a violation of this section since this section does not require implementation of any standard but failure to do so could violate otherwise applicable State law, where such law, for example, requires the regulatory body to act in accordance with determinations made on the record.

Another result could be a determination that the standard is inappropriate to carry out the purposes but consistent with otherwise applicable State law. In this case, nothing in the legislation would require implementation or bar implementation.

Still another possible case is that a standard is not appropriate to carry out the purposes of this title and is inconsistent with otherwise applicable State law. In this case, nothing in the legislation would support any State regulatory authority (or nonregulated utility) or any court in implementing the standard.

Another option is that the standard was determined approp[illegible]e to carry out the purposes but inconsistent with otherwise applicable State law. In this case, otherwise applicable State law governs and prevents the implementation of the standard.

In any case in which the State regulatory authority with respect to a particular State regulated electric utility or nonregulated utility determines not to implement a Federal standard determined to be appropriate to carry out the purposes of the title, a statement of the reasons for such determination is required. The requirement of the statement is intended to provide information to the parties and the public.

With respect to each of the standards, the State authority or nonregulated utility may decide to partially implement the standard, such as moving toward cost of service, but not fully implementing the standard in that regard. Alternatively, a State regulatory authority or nonregulated utility may decide to phase in the implementation of the standard in several steps, or decide not to implement the standard.

In considering the standards set forth in this section, it is expected that State regulatory authorities and the nonregulated utilities take into account the need to protect ratepayers against sudden shifts in electric utility rates which might lead to significant economic hardships. The State regulatory authorities and nonregulated utilities may consider phasing in the implementation of the standards, providing for temporary exemptions from implemented standards, or providing other means determined appropriate by the State authorities or the nonregulated utilities to mitigate any such hardships.

States are also, of course, free to implement, pursuant to State authority, cost of service based rates, time of day rates, seasonal rates, and other concepts related to any standard established by this subtitle even if the standard which is related to such concept is not determined to be appropriate to carry out the purposes of this title.

Any determination that it is inappropriate to implement a standard will be made in writing and available to the public as provided in subsection (c) (2).

Subsection (d) establishes the Federal standards to be considered under this procedure: cost of service, declining block rates, time of day rates, seasonal rates, interruptible rates, and load management techniques.

The time of day and seasonal standards are intended to structure rates so as to lower the peaks and fill the valleys of the load curves because to do so may reduce the need for more expensive peaking generation and otherwise carry out the purposes of the title. With respect to time of day and seasonal rates, the conferees do not intend that time of day or seasonal variation in rates exactly reflect the time of day or seasonal variation in costs of providing service. A less than proportional increase in rates at the peak may be appropriate to send the signal to the consumer to reduce elastic demand for peak energy without causing unnecessarily high rates which have no effect on inelastic demand at the peak.

The standard concerning seasonal rates does not contain any qualification reflecting cost effectiveness. The cost of reflecting seasonal variations in cost does not involve the use of time of day metering equipment or other expenses at the consumer's end of the line. However, State regulatory authorities (and nonregulated electric utilities) may choose to disregard insignificant seasonal variations in costs of providing electric service. A variation of the rates based upon these insignificant variations in costs is not necessary to reflect costs accurately to consumers or otherwise carry out the purposes of this title.

Section 112. Obligations to consider and determine

The first purpose of this section is to authorize each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility to undertake the consideration and determination referred to in section 111. The second purpose is to require each State regulatory authority and each nonregulated utility to consider and to make a determination (as described in section 111(a)) with respect to any of the six Federal standards established by section 111(d) when requested to do so by a participant or intervenor in any proceeding relating to rates. The final purpose is to set out the time limitations under which the process of consideration and determination must begin and be completed for each of the six standards. The section prescribes the consequences of failure to complete by the specified time the determination for each of the six standards with respect to a particular utility. In that event the State regulatory authority or nonregulated utility, as the case may be, must at the next rate proceeding applicable to the electric utility which begins after the end of this 3-year period, make the determination for each of the six standards for which a determination has not been made.

The conferees intend that State regulatory authorities and nonregulated utilities consider each of the standards specified in section 111(d) whether or not electric utilities, intervenors, or other parties raise them in rate proceedings. That is the purpose of the time limits in this section—to insure expeditious consideration once with the obligation being on the State regulatory authority, or nonregulated utility, without any other action by any other person to initiate such consideration. At any time, parties to any proceeding relating to rates or intervenors in such a proceeding may raise any of these standards for consideration. The conference substitute does not permit a person to initiate a proceeding for this purpose. However, if a proceeding has been initiated under State law, a person eligible under section 121 may intervene and require such consideration and determination in such proceeding. If the rate case or other proceeding has already begun, no new notice is required if there was adequate prior notice to apprise persons that the issues may be raised.

The conferees are aware of the problems of delay in consideration of rate cases. It is not the intention of the conferees that the requirement of this section for the consideration of any standard upon request of a party or intervenor be used solely for purposes of delaying the rate proceeding process. Even though an intervenor in any rate case can force consideration as specified in section 112(a), the State regulatory authority or nonregulated utility may take into account in such proceeding any appropriate prior determination with respect to such standard and the evidence upon which such determination was based

Any proceeding related to such determination may have taken place after the date of enactment of this Act, or prior to such date, or have been pending on such date, although in the latter two cases, the requirements of this title as provided in section 124 apply. It is not the intention of the conferees that, if a standard has been considered in accordance with the requirements of this title, the second process of consideration and determination be necessarily as extensive as the first. Of course, the State court may rule, on review, that reliance on prior determinations or evidence was properly placed or improperly placed. Reliance on a prior determination does not relieve the State regulatory authority or nonregulated utility from meeting whatever burden is imposed under State law.

The State regulatory authority or nonregulated utility has no obligation to make any determination under section 111(b) with respect to concepts (other than the standards listed in section 111(d)) which are claimed to contribute to the achievement of the purposes of this title, and which are raised pursuant to an intervenor or participant's right under section 121.

Section 113. Adoption of certain standards

The purpose of this section is to establish a second group of Federal standards with respect to electric utilities. Unlike the first group established by section 111(d), some of these standards are not directly related to the rate structure of the electric utility, but rather relate to other practices of electric utilities regarding terms and conditions of electric service that may indirectly affect the rate structure of the utility.

The conferees intend that the discretion under this title of a State regulatory authority or nonregulated electric utility to adopt the standards established by section 113 or not adopt them or to implement the standards established by section 111 or not implement them is very broad, so long as the requirements of this title are met. Such authority and utility are not required by these sections to adopt or implement such standards. However, any provisions of State law or regulations that may require such adoption or implementation are not affected by this title.

The conferees wish to emphasize that for purposes of the determination in accordance with paragraph (1) or (2) of section 113 and for the purposes of any review of the consideration and determination in any court, the purposes of this title supplement State law.

It should be noted that the test of consistency with State law, as described in section 113(a) (1) and (2) is with respect to State law alone and not with respect to State law as supplemented by the three purposes of the title. The intent here is that where a State regulatory commission or nonregulated utility finds insufficient authority pursuant to otherwise applicable State law, under which it may adopt a standard established in section 113, then these three purposes of the title provide such authority. In effect the three purposes expand the discretion of the State regulatory commission or nonregulated utility to adopt the standards of section 113. However, the conferees also intend that three purposes do not override State law.

The last sentence of section 113(a) states that nothing in this subsection prohibits any State regulatory authority or nonregulated utility from making the determination that it is not appropriate to implement any such standard pursuant to its authority under otherwise applicable State law. The intention here is to preserve the discretion of the State regulatory authorities and nonregulated utilities which is provided by State law, except to the extent this title imposes procedural requirements such as requirements to hold a hearing, consider and make a determination.

Thus, in making its determination under section 113, the State regulatory authority or nonregulated electric utility may consider, in addition to the 3 purposes of this title, any other factors which State law would permit for consideration in the proceeding.

For example, if the State constitution or State law affords the State regulatory authority or nonregulated utility broad discretion to consider any factors, as documented in the hearing record, that they deem appropriate, then those factors may serve as a basis for the decision of the State regulatory authority or nonregulated utility, either to adopt any standard under this title or to reject it.

This section requires each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated utility after public notice and hearing, to adopt these standards if, and to the extent such adoption is determined appropriate to carry out the purpose of this title, is otherwise appropriate, and is consistent with otherwise applicable State law. In the case of the standard related to termination of service, such authority or utility must adopt this standard if, and to the extent such adoption is appropriate and consistent with otherwise applicable State law. Any adoption is on a utility-by-utility basis. The conferees treated termination of service differently from the other standards in this section because this provision is generally not related to these purposes but is an important provision to protect consumers from inappropriate terminations of service.

This section requires each State authority and each nonregulated utility to examine these standards in a hearing within two years after enactment. This section does not require a State regulatory authority or nonregulated utility to undertake the consideration of these standards as provided in section 112(a) whenever an intervenor or participant raises them in any rate proceeding as provided with respect to the standards set forth in section 111(d). Neither does it preclude the consideration and adoption of any of the standards under otherwise applicable law.

The conferees expect that the modifications of the standards described in this section may meet the test of appropriateness in the context of a particular potential application. The conferees therefore understand that individual States (or utilities) may choose to adapt the standards to their particular situation as documented in the record of the hearing held to examine the standard.

This second group of five standards consists of the following: master metering, automatic adjustment clauses, information to consumers, minimum procedures for termination of electric service and advertising.

With regard to the standard for master metering, the conferees leave the matter of what is a new building to the States for their determination. The States should be guided by the cost of purchasing and installing individual meters in the building after the date of adoption of the standard balanced against the energy to be saved over the anticipated useful life of the building. The conferees believe that the case for adopting the standard is stronger if the person using the space in a building uses significant amounts of electric energy and controls its use and the installation of meters would be cost effective. There is no intention here to have State regulatory authorities or nonregulated utilities dictating the design of buildings, the choice or design of heating systems, cooling systems, or any other such energy consuming systems in buildings. Rather, this standard goes only to the choice of whether, given a specific multiunit building, the electrical consumption in the building will be measured by a master meter or by use of individual meters in the separate dwelling units.

The conferees stress that the standard on advertising prohibits recovery of expenditures for promotional or political advertising from anyone "other than the shareholders (or other owners)" of the utility, instead of prohibiting recovery from the electric consumers of the utility, as did the House bill. Without this change from the House bill, utilities for which the owners are also the electric consumers, i.e. cooperatives, could be effectively prohibited from undertaking any political or promotional advertising if this standard were adopted. Adoption of the standard does not prohibit any utility from engaging in this kind of advertising. The standard merely specifies who is to pay for the advertising.

Subsection (c) of this section contains the procedural requirements which attach to a decision not to adopt each of these standards. In such a case, the State regulatory authority or nonregulated electric utility shall state in writing which of the standards it has determined not to adopt and the reasons therefor. Adoption of standards which vary insignificantly from the standards spelled out in this section may be treated as adoption of the standards for purposes of this subsection.

Section 114. Lifeline rates

This section was adopted from the House bill with technical changes. The purpose of this section is to authorize lifeline rates as an exception to the Federal standard on cost of service (section 111(d)(1)). Thus, if a State regulatory authority or nonregulated utility, as the case may be, adopts the Federal standard on cost of service, this legislation would not prohibit the adoption of lifeline rates as well, even though a certain portion of the charge to residential electric consumers would not necessarily reflect the cost of providing service to them.

A second purpose of this section is to require each State regulatory authority and each nonregulated utility to determine after an evidentiary hearing whether a lifeline rate should be implemented if any particular utility, covered by the legislation and under the ratemaking authority of the regulatory authority, or the nonregulated utility, as the case may be, does not have a lifeline rate. This provision provides a full hearing on this issue at the State level, with no judgment made in Federal law as to how it should be resolved.

Subsection (c) provides that section 124 shall not apply to the requirements of this section. The conferees intend that the hearing be held after the date of enactment of this legislation and prior proceedings held before that time not be referenced as complying with these requirements.

ards (in the material relating to section 115) is to apply in the same manner to the special rules under this section for gas utilities.

Section 305. Federal participation

This section is taken from the Senate amendment and grants the Secretary authority to intervene on his own motion in certain proceedings before State regulatory authorities and nonregulated gas utilities to advocate policies and methods that achieve the purposes in section 301.

Subsection (a) grants new authority, in addition to that contained in existing law, to the Secretary of Energy to intervene on his own motion in any proceeding before a State regulatory authority which relates to gas utility rates or rate design. The Secretary is only to intervene under the authority of this section to advocate policies or methods which achieve the three purposes stated in section 301.

Subsection (b) grants the Secretary the same rights as any other party to a proceeding before a State regulatory authority in which the Secretary is authorized by this section to intervene. Such proceeding must be related, however, to gas utility rates or rate design.

Subsection (c) grants to the Secretary the same rights as any other party to a proceeding before a nonregulated gas utility, if the Secretary is authorized by this section to intervene in such a proceeding.

In the case where the nonregulated utility sets its rates or rate designs without proceedings that are appropriate for intervention, the Secretary is permitted to review those rates or rate designs, notify the nonregulated utility of his recommendations to carry out the purposes of section 301 and such notification must be made available to the public.

Section 306. Gas utility rate design proposals

Both the Senate bill and the House bill contained a provision on gas utility rate design proposals. Based upon this study the Secretary is directed to develop proposals to improve gas utility rates and encourage conservation of natural gas. The Secretary is directed to transmit the proposals and specified analyses to Congress within 12 months after the date of enactment.

Section 307. Judicial review and enforcement

This section provides for the judicial review of actions arising under this title and for enforcement of the requirements of this title.

Subsection (a) expressly limits Federal jurisdiction, regarding any action arising under this title, to only two situations. First, the Secretary may bring an action in the appropriate Federal court to enforce his right to intervene under section 305. Second, the Supreme Court would have jurisdiction in accordance with sections 1257 and 1258 of title 28 of the United States Code to consider any action upon appeal from the highest court of any State. Aside from these two exceptions no Federal court has jurisdiction over any action arising under this title.

This section provides for judicial review and enforcement of this title in State court but only if, either, the person seeking review was a participant or intervenor in the original proceeding, or if State law otherwise permits such review. The conferees' agreement provides that

any such review will be conducted in accordance with the applicable State procedures.

This section expressly provides that this title provides no authority for the Secretary to appeal or otherwise seek judicial review of the decisions of a State regulatory authority or nonregulated gas utility, or to be a party to any action to obtain review or appeal of such a decision.

Finally, this section grants the Secretary the authority to participate as an amicus curiae in any judicial review of an action arising under this title.

Section 308. Relationship to other applicable law

Since this section is parallel to section 117(b), the explanation set forth earlier in this statement respecting electric utilities under section 117(b) is intended to apply in the same manner to gas utilities under this section.

Section 309. Reports respecting standards

This section parallels section 116 of title I. The conferees intend the explanation in this statement concerning section 116 is to apply as well to this section.

Section 310. Prior and pending proceedings

This section parallels section 124. The conferees intend the explanation in this statement concerning section 124 is to apply as well to this section.

Section 311. Relationship to other authority

This section parallels section 131. The conferees intend the explanation in this statement concerning section 124 is to apply as well to this section.

TITLE IV—SMALL HYDROELECTRIC PROJECTS

Section 401. Establishment of program

This section establishes a program to be administered by the Secretary to provide incentives for the construction of small hydroelectric power projects in connection with existing dams. The provisions described below incorporate a loan program to help fund feasibility studies and application preparation, as proposed in the Senate bill, and a loan program to help fund the costs of constructing projects, as proposed in the House bill. The conference substitute includes provisions directing the Commission to establish a simple and expeditious licensing procedure for such projects.

Section 402. Loans for feasibility studies

This section authorizes the Secretary to make loans of up to 90 percent of the costs of conducting feasibility studies and preparing and providing applications for a license or other Federal, State and local approvals.

The Secretary shall cancel the unpaid balance and any accrued interest on any loan granted under this section if he determines on the basis of a feasibility study that the proposed project would not be technically or economically feasible, except that the Secretary shall not cancel the unpai[illegible] ance and accrued interest on any loan pursuant to the section if he finds that the applicant, in applying for the loan, failed to provide information reasonably available to such applicant which would have indicated that there was not a reasonable likelihood that the project might be found to be technologically and economically feasible.

The conferees intend that the Secretary should take reasonable steps prior to approving a loan pursuant to the section to determine that, on the basis of available information, there exists a reasonable likelihood that the project may be found to be both technically and economically feasible. Any determination under this section as to economic feasibility shall include consideration of costs associated with environmental and safety factors.

The conference substitute provides that no part of any loan under this section may be used to defray any part of any fee charged by any Federal, State or local agency as condition of receiving a license or other approval from such agency.

In cases where there are two or more proposed projects located upon the same waterway, the Secretary may approve one loan for a single feasibility study dealing with all such projects (in which the persons proposing the projects will jointly participate) even though such projects are proposed by different persons, if he finds that to do so would avoid unnecessary duplication of effort and costs and would provide adequate information to make a determination concerning the feasibility of all such projects.

Before making a loan for feasibility studies to any applicant, the Secretary shall consult with the Commission to determine whether any other person may be entitled to priority consideration by reason of the issuance by the Commission of a preliminary permit under part I of the Federal Power Act. The Secretary shall take such priority into consideration in determining whether or not to make a loan under this section to such applicant.

Section 403. Loans for project costs

The conference substitute includes provisions authorizing the Secretary to make loans to eligible persons of up to 75 percent of project costs of small hydroelectric power projects which meet criteria set forth in the section. It was agreed that the costs of constructing fish and wildlife facilities required in connection with such projects should be included in project costs to the extent that other public funds are not available for that purpose.

Since licenses may not be issued in some cases unless financing is available, the conference substitute provides that the Secretary may make a commitment to make a loan to a person who has not met the requirements of paragraph (2), pending compliance by such person with these requirements. The commitment shall be for a period of not to exceed 3 years unless the Secretary, in consultation with the Commission, extends such period for good cause shown. Notwithstanding any such commitment, no loan shall be made before such person has complied with these requirements.

The conference substitute incorporates a provision directing the Secretary to give preference to applicants who do not have available alternative financing which the Secretary deems appropriate to

carry out the project. It was intended that under this provision preference should be given to applicants for projects for which other sources of financing are unavailable or, if available, are only available at a cost that might render the project economically infeasible. The conferees also agreed that an important part of the responsibility of the Secretary under the section is to encourage investors from the private sector to participate in projects with applicants who in the Secretary's opinion have not in the past had ready access to private sources of financing for such projects.

In directing the Secretary to encourage joint participation by applicants, the conference substitute encourages the broadest possible cooperation between qualified applicants in developing and utilizing energy from each individual small hydroelectric project rather than to encourage cooperation between applicants for two or more projects.

Section 404. Loan rates and repayment

The conference substitute provides that every loan made pursuant to this title shall bear interest at the discount or interest rate used at the time the loan is made for water resources planning projects under section 80 of the Water Resources Development Act of 1974 and shall be for such term, as the Secretary deems appropriate, but not in excess of (1) 10 years (in the case of a loan under section 402) or (2) 30 years (in the case of a loan under section 403). Amounts repaid on loans made pursuant to this title shall be deposited into the Treasury as miscellaneous receipts.

Section 405. Simplified and expeditious licensing procedures

The conference substitute provides that the Commission shall establish a program to use simple and expeditious licensing procedures under the Federal Power Act for small hydroelectric power projects in connection with existing dams.

Before issuing any license under the Federal Power Act for the construction or operation of any small hydroelectric power project the Commission is directed to assess the safety of existing structures in any proposed project (including possible consequences associated with failure of such structure), and to consult with the Council on Environmental Quality and the Environmental Protection Agency with respect to the environmental effects of such project.

Nothing in this subsection exempts any project from any applicable requirement under the National Environmental Policy Act of 1969, the Fish and Wildlife Coordination Act, the Endangered Species Act, or any other provision of Federal law.

The Commission is also directed to encourage applicants for licenses for small hydroelectric power projects to make use of public funds and other assistance for the design and construction of fish and wildlife facilities which may be required in connection with any development of such project.

Section 406. New impoundments

The conference substitute provides no authorization for the loan of funds for construction of any new dam or other impoundment, or the simple and expeditious licensing of any new dam or other impound-

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ment. This section does not restrict authority available to the Commission under other law.

Section 407. Authorizations

The conference substitute authorizes the appropriation for each of the fiscal years ending September 30, 1978, September 30, 1979, and September 30, 1980, $10 million for loans to be made pursuant to section 402, such funds to remain available until expended. It also authorizes the appropriation for each of the fiscal years ending September 30, 1978, September 30, 1979, and September 30, 1980, of $100 million for the loans to be made pursuant to section 403, such funds to remain available until expended.

Section 408. Definitions

In defining "small hydroelectric power project" for the purpose of this title, the conferees intended that the phrase "at the site of an existing dam" should be strictly construed to mean at the site of an existing impoundment.

The term "project costs" includes any insurance costs related to the construction of the project.

TITLE V—CRUDE OIL TRANSPORTATION SYSTEMS

Section 503. Definitions

In adopting the definitions of "crude oil transportation system" and the "Long Beach-Midland project", the conferees agreed that the national interest may require the operation of new systems for delivering oil from west to east. The conferees also agreed that, while the Long Beach-Midland project, if approved, is to be a pipeline to transport crude oil between two known points and over a specific known route it is not the intent of Congress to limit in any way the consideration of crude oil transportation alternatives serving the Northern Tier States, either as the method of transporting oil, or the route to be followed. Finally, the conferees agreed that the Long Beach-Midland project and any proposals for a crude oil transportation system shall be treated as entirely unrelated delivery systems and that any consideration or decision regarding one shall have no bearing on considerations or decisions regarding the other.

Section 504. Applications for approved of proposed crude oil transportation systems

The conferees adopted language providing that applications for the construction and maintenance of a crude oil transportation system submitted to the Secretary of Interior shall be eligible for consideration under the title if they are received by the Secretary before the 30th day after the date of enactment of the Act. Applications received by the Secretary during the 60-day period beginning on the 30th day after the date of enactment of the Act will also be eligible, if the Secretary determines that consideration and review of the proposals contained in such applications is in the national interest and that such consideration could be completed within the time limits established under this title. The conferees agreed that while it was the intent of Congress that any proposals for crude oil transportation systems submitted pursuant to this title should be given full consideration, it is not the intent of Congress that the Secretary be required to entertain applications which he finds speculative in nature and unlikely to be approved within the time limits established under this title.

Section 505. Review schedule

The conferees adopted language directing the Secretary to establish an expedited schedule for conducting reviews and making recommendations concerning crude oil transportation systems proposed in applications under the title. The conferees agreed that while it is the intent of Congress that reviews and recommendations pursuant to this title should be expedited, it is also the clear intent of Congress that the schedule for such review and recommendations not be so restrictive as to limit full consideration of reasonable alternatives that could possibly be approved within the schedule provided under this title.

The conferees adopted a provision authorizing the Secretary of the Interior on his own initiative, or on the request of the head of any Federal agency covered by the review schedule established pursuant to subsection (a) of the section, to require that an applicant provide such additional information as may be necessary to conduct the review of the applicant's proposal.

The conferees also adopted language providing that nothing in the title shall bar the Attorney General or any other appropriate officer or agent of the Federal Government from challenging any anticompetitive act or practice related to the ownership, construction or operation of any crude oil transportation system approved under the title. They further specified that approval of any such system shall not be deemed to convey to any person immunity from civil or criminal liability or to create defenses to actions under the antitrust laws, nor shall such approval modify or abridge any private right of action under such laws. The conferees agreed that the provisions regarding antitrust laws under the title may not be construed as affecting State antitrust laws or the existing relationship between Federal and State antitrust laws. Thus, for example, if a Federal law has preempted a State law, a waiver of any provisions of such Federal law shall not be construed to reinstate any provisions of the preempted State law.

Section 506. Environmental impact statements

The conferees adopted language requiring that on or before December 1, 1978, all environmental impact statements concerning proposed crude oil transportation systems eligible for consideration under this title shall be completed, made available for public review and comment, revised to the extent appropriate in light of such comment and submitted to the President and the Council on Environmental Quality; except that in the case of any environmental impact statement concerning a system eligible for consideration and filed under section 504(2) of the title, such actions may be taken not later than 60 days after December 1, 1978. The conferees agreed that for the purposes of the section a "completed" environmental impact statement means a statement in regard to which the actions of the responsible Federal agencies have been completed and does not include the completion of any court review with regard to such statement or such actions.

Section 507. Decision of the President

The President shall make a decision within 45 days on which proposal, if any, shall be approved. If the President determines that a proposal which filed late appears to have merit, he may delay his decision for an additional 60 days beyond the 45-day period provided for under this title.

In adopting language setting forth the criteria to be considered by the President in making a decision under the section, the conferees agreed that the provision requiring the Executive to consider the "environmental impacts of the proposed systems and the capability of such systems to minimize environmental risks resulting from transportation of crude oil" should be understood as setting forth the intent of Congress that the Executive should take actions to minimize both existing and future environmental risks from the transportation of crude oil. In specific, the conferees noted that there are environmental and economic risks associated with the existing crude oil tanker traffic serving refineries on Puget Sound—an invaluable and irreplaceable national resource. Risks to the economically and aesthetically important resources dependent on good water quality in Puget Sound would be substantially reduced if the existing Washington refineries were connected to and utilized a northern crude oil delivery system, if one is built. This position is consistent with the federally approved Washington coastal zone management program.

Section 508. Procedures for waiver of Federal law

The conferees authorized the President to identify those provisions of Federal law (including any law or laws regarding the location of a crude oil transportation system) which, in the national interest as determined by the President, should be waived in whole or in part to facilitate construction or operation of any crude oil transportation system approved under section 507 of the title or the Long Beach-Midland project.

The conferees agreed that this should be construed as authorizing the President to consider provisions of law restricting the location of any part of a project or an approved system, or related facilities of such a project or system, and to propose the waiver of such provisions if he determines such waiver to be in the national interest.

The conferees also adopted a provision specifying the language of the joint resolution to be used by the President in proposing a waiver of provisions of law under this section and establishing procedures for the consideration of such joint resolution by the House of Representatives and the Senate.

The conferees agreed that all the provisions of law, if any, for which the President proposes a waiver in connection with the Long Beach-Midland project shall be included in one joint resolution which may be submitted to Congress at any time after the date of enactment of the act. All the provisions of law, if any, for which the President proposes a waiver in connection with an approved crude oil transportation system under this title, shall be included in another joint resolution which may be submitted to Congress after the President has approved such system under section 507 of the title.

At the time of submission to Congress of any joint resolution proposing a waiver of provisions of law under this section, the President shall specify which system or project is the subject of such joint resolution. Enactment of such joint resolution, consistent with the requirements of the section, shall waive such provisions only for the system or project which is the subject of the enacted joint resolution.

The conferees noted that actions by the State of California have resulted in delays in the construction and operation of the Long Beach-Midland project. They expressed concern over the possibility of continuing delays on the part of the State that may adversely affect the interests of the people of California and the Nation.

TITLE VI—MISCELLANEOUS PROVISIONS

Section 601. Study concerning electric rates of State utility agencies

Section 601 is a study concerning the effects of provisions of Federal law on rates established by State utility agencies. The study is to be conducted by the Secretary, in consultation with the Commission, appropriate State regulatory authorities, and interested persons. The Secretary shall submit a report to the Congress containing the results of the study within a year after the date of enactment of the Act.

The conferees intend that the term "Federal laws" not include environmental laws, health and safety law, or tax laws or other laws not relating to the concerns expressed in the House provision. The section also defines the term "State utility agency" as an agency of a State which is an electric utility. The term does not include any political subdivision or agency thereof or any public power district.

This section is a modification of a provision in the House bill which required rates of a State utility agency to be based on the total costs of all electric energy generated by all facilities of the entire system of the agency together with all electric energy purchased by the agency. The House provisions prohibited the assigning of the output of a specific generating facility and its corresponding cost of electric service to a specific customer rather than aggregating all output and corresponding cost of service for purposes of the rates of all electric customers of the agency.

In adopting a study in lieu of the mandatory requirements in the House, the conferees do not intend to affect a State's or State utility agency's determination as to how it should establish rates with regard to electric energy or to affect the authority of the State or State utility agency to continue, as authorized by law, to follow present practices in this regard.

Section 602. Seasonal diversity electricity exchange

The Senate bill contained a provision that would authorize the use of Federal eminent domain authority by private parties to acquire property interests necessary to construct an electrical transmission line called the Mandan line from Manitoba, Canada to North Dakota, South Dakota, and Nebraska. The exercise of the power of eminent domain would be conditional on the parties acquiring a Presidential permit for transmission facilities at the international border. The House bill contained no comparable provision.

The c[illegible] rees understand that the purpose of the Mandan line is to facilitate the exchange of electric power to take advantage of the complementary seasonal variation in energy demand in Canada and the States through which the line would pass. Such an exchange could contribute significantly to the more efficient use of existing power production facilities, thereby reducing the pressures on capital resources for construction of new generation facilities. The conference substitute establishes a mechanism to provide for the acquisition of rights-of-way for the construction of this line which, because of its unique, international, and interstate nature, may require the use of such authority.

However, the conferees stress that before such authority may be used, the determinations required by this section must be made and they must result in an affirmative determination by the Secretary. If the Secretary makes the required determinations, the conferees intend that the Secretary have the full authority necessary to expedite the project subject, of course, to the provisions of this section.

The conference substitute authorizes the Secretary of Energy in his discretion to acquire rights-of-way by purchase, including the use of eminent domain, through the above States for transmission facilities. The conferees believe that the Secretary may be able to keep acquisition costs down through this purchase authority. Before such acquisition, the Secretary of Energy, after an opportunity for public hearings must make several determinations. He must determine that the exchange of power is in the public interest and that it would further the purposes of section 101(1) and (2) of this Act. It is the intention of the conferees in subsection (a)(1)(A) that, for this exchange to be considered to further these purposes, it is not necessary that both of these purposes must be furthered. The conferees intend that it would further the purposes referred to in section 101(1) and (2) if either of these purposes are furthered and the other is not negatively impacted.

The Secretary must also find that the acquisition of such rights-of-way and the construction and operation of the facilities would be in the public interest. He must also be assured that a permit to cross the international border has been issued. In addition, he must determine that each affected State has approved each portion of the transmission route that is to be located in that State. He must determine, after consultation with the Secretary of the Interior and other affected Federal agencies, that each concurs with the location of the route of the transmission line across any Federal lands under their jurisdiction and any related requirements. The objective of this provision is to protect Federal lands that may be utilized for this transmission line.

In the case of the State approval, the conference substitute provides authority for the Secretary to cooperate with the States and provide technical assistance, subject to the availability of funds, in determining what is an appropriate transmission route. If the transmission route approved by one State does not appear feasible or in the public interest or if the States are in disagreement as to the siting of the route, the Secretary should encourage the States to review the route and to develop a route that is satisfactory and meets the concerns of the States.

The authority of the Secretary to exercise eminent domain would be carried out in accordance with normal statutory provisions providing for declarations of taking and other matters under Federal law (i.e. 40 U.S.C. 257 and 258a and Rule 71a of the Federal Rules of Civil Procedure).

The section requires that the Secretary provide public notice of his intention to acquire the right-of-way before he exercises the power of eminent domain with respect to such right-of-way. Such notice is not necessary if he plans to acquire it by purchase.

Subsection (b) of the conference substitute requires that before a permit can be issued for the crossing of the international border, the Commission must make findings concerning that crossing.

Subsection (c) requires that before the Secretary acquires a right-of-way, the holders of the permit must show that they are unable to acquire the right-of-way, without unreasonably delaying construction, by condemnation under State authority or that they have tried to negotiate for the right-of-way but have been unable to reach satisfactory agreement. The conferees intend that the Secretary not delay the holders of the permit indefinitely in this regard but that he merely satisfy himself that the permittees have made an earnest effort to negotiate but have been unable to do so.

Subsection (d) provides for the transfer of the right-of-way acquired by the Secretary to the holders upon their paying to him the cost of the acquisition, including the administrative costs. Such payments will be deposited in the Treasury as miscellaneous receipts. The Secretary could, however, reach agreement with the holders that they provide to him the funds for the acquisition, including administrative costs, so that he does not have to use appropriated funds. If the holders fail to make the payments required, then the Secretary must offer the right-of-way, after a reasonable time, to the original owner. The original owner could reacquire it at the same amount paid by the Secretary for the right-of-way. If the original owner does not want to reacquire it after a reasonable period, then the Secretary can dispose of it under other provisions of law.

Subsection (e) makes it clear that the section does not in any way affect Federal laws governing Federal lands. There are a number of Federal statutes relative to national parks, fish and wildlife refuges, and other areas which establish conditions or other requirements concerning the use of those lands for purposes other than those for which they were acquired or withdrawn. Those statutory provisions would apply to these rights-of-way. They are not intended to be overridden or affected in any way by this conference agreement.

Subsection (f) requires an annual report to the Congress about the actions taken. If the Secretary does not take any action under the agreement in any particular year, no report is required.

Section 603. Utility Regulatory Institute

The Senate bill contained a provision that authorized the Secretary of Energy to make grants to an institute established by the National Association of Regulatory Utility Commissioners "to provide State regulatory authorities with an independent source of applied economic and technical research on critical regulatory policy issues and with imp...ved data retrieval systems." The House bill contained no comparable provision.

The conferees adopted a modified version of the Senate provision. Matching grants were substituted for the 100 percent grants contained in the original provision and restrictions were placed on the terms and conditions that the Secretary of Energy may impose on the matching grants. In particular the Secretary may impose only such terms and conditions as he deems necessary to administer this section, to assure that any information gathered by the Institute is available to the public, and to assure that none of the Federal funds are used to support or oppose any legislative proposal, unless a representative of the institute is invited to testify before a committee of Congress or before a State legislature.

The Senate bill contained a provision which reversed a General Services Administration decision with respect to rent allowance for office space provided to the National Association of Regulatory Utility Commissioners. The Senate receded to the House and this provision was deleted in the conference substitute with the understanding that the General Services Administration will review its decision. The conferees do not intend that such review in any way prejudice the result of such review. The General Services Administration could modify, or reverse the decision or let it stand as is.

Section 604. Coal research laboratories

The conference agreement adopts with some modifications the Senate amendment to the Surface Mining Control and Reclamation Act of 1977 increasing from ten to thirteen the number of institutions of higher education at which coal research laboratories will be established and operated. The Secretary of Energy is required to make the designations. The first ten of the designations shall be made, as required in present law, in accordance with section 801(e).

The conferees, in adding more designations, do not intend to affect or slow down the designations and their related actions required by the 1977 law to establish the first 10 institutions. The agreement also continues the requirement that these ten be located only in States with abundant coal reserves. The other three are not required to be located in such States. The other two criteria of existing law apply to all of the designations. Funds for the three additional institutions are provided beginning in fiscal year 1980.

Section 605. Conserved natural gas

The Senate amendment provided that no action of the Federal Energy Regulatory Commission shall directly or indirectly take natural gas from any natural gas utility if the utility demonstrated that the natural gas was conserved as a result of energy conservation measures. A schedule for allocation of such conserved gas among the utility's customers was set forth. The House bill had no comparable provision.

The conference substitute deals with this issue in the following manner. Curtailment plans establish priorities for the delivery of natural gas when supplies are insufficient to meet contract demand. In most cases, a local distribution company's entitlement to natural gas under a curtailment plan is determined by reference to the priorities of use,

and volumes of gas used, by its customers during a particular base period.

Since the base period, some local distribution companies have established conservation programs which have conserved natural gas. For example, as the result of a residential conservation program established by the distribution company, natural gas may have been made available to a local industrial user. If the base period is updated, the user profile of this local distribution company could thereby include a larger proportion of low priority use, and under certain circumstances, the local distribution company's entitlement could be reduced. This result would discourage local distribution companies from establishing such conservation programs.

If an updating of the base period occurs, section 605 requires that under certain circumstances the Commission must consider volumes of conserved natural gas as being used for the same priority as the priority for which the gas was used in the prior base period. Thus a local distribution company will not be penalized for implementing a conservation program.

The Commission must determine what conservation measures qualify for consideration under the section and the methods by which the volumes of conserved gas are to be measured. It is the intention of the conferees that such measures include any conservation measures mandated by law. The conserved gas must be the direct result of conservation measures implemented by the local distribution company.

A change in a curtailment plan which does not require an updating of the base period data, such as the revisions required in title IV of the Natural Gas Policy Act of 1978, would not trigger the application of this section.

An example may help to explain the operation of the section. A local distribution company had customers using natural gas in the following manner during 1972, the base period: 50 MMcf for Priority 1; 30 MMcf for Priority 2; 20 MMcf for Priority 3. As the result of a conservation program, Priority 1 users saved 10 MMcf, which is now used for Priority 3 uses. The new use profile, therefore, is: 40 MMcf for Priority 1; 30 MMcf for Priority 2; 30 MMcf for Priority 3. If the Commission chooses to update the base period and the local distribution company demonstrates that the 10 MMcf of Priority 1 use was conserved by the distribution company through approved conservation measures, then 10 MMcf used for Priority 3 in the revised base period would be deemed to be used for Priority 1, and the revised use profile would be identical to the earlier profile.

Section 606. Voluntary conversion of natural gas users to heavy fuel oil users

The Senate amendment directed the Federal Energy Regulatory Commission to promulgate regulations under which electric utilities and major fuel-burning installations could voluntarily transfer their contractual rights to receive natural gas supplies in exchange for just compensation. The regulations were required to allow such sales only by those electric utilities and major fuel burning installations which, on the date of enactment of the legislation, own or have contracted for natural gas supplies and have an ability to burn heavy petroleum fuel oil in lieu of natural gas. The Senate provision authorized sales for a maximum of five years and in no case were sales permitted to extend beyond December 31, 1989.

The Federal Energy Regulatory Commission was to determine the level of just compensation which could be received by an electric utility or major fuel-burning installation which converted from the use of natural gas to heavy petroleum fuel oil. Such compensation was to include at least:

(1) the cost of the substituted heavy petroleum fuel;

(2) the cost of transporting, handling, and storing the substitute fuel;

(3) increased costs of power plant operations and maintenance attributable to use of the substitute fuel and decreased fuel efficiency; and

(4) a proportionate share of the average cost of the seller's gas system.

The Senate bill also provided for compensation to any intrastate pipeline which lost revenue due to the transfer of contractual rights to receive natural gas.

The Senate amendment provided a statutory exemption from the provisions of the Natural Gas Act for persons engaged in the transfer of contractual interests under the section.

The House bill contained no comparable provision.

The conference substitute deals with this matter as set forth in section 606. In order to facilitate the conversion of electric utilities and major fuel-burning installations from the use of natural gas to the use of heavy petroleum fuel oil, the conferees agreed to substitute provisions based upon the Senate provision. The conference substitute requires the Commission to establish a mechanism whereby the transfer of contractual interests involving the receipt of natural gas may be approved by the Commission.

The section applies only to intrastate natural gas, received by the user pursuant to a contract entered into before September 1, 1977, for use as a fuel in a facility in existence on September 1, 1977. The Commission's rule must permit the transfer of contractual interests by the person using such natural gas to an interstate pipeline, to any local distribution company served by an interstate pipeline, or to any person, served by an interstate pipeline, for a high priority use by such person. The Commission is authorized to prescribe terms and conditions under which the transfer of contractual interests under this section may proceed.

The section requires the Commission to establish a mechanism for refund of any consideration received by the person transferring contractual interests under this section if the consideration actually received exceeds the amount by which the costs, actually incurred by the transferor in association with the substitution of heavy petroleum fuel oil, exceeds the price of natural gas under the contract with respect to which contractual interests were transferred under this section. The purpose of the compensation provisions is to make the transferor whole for any expenses incurred, including increased costs related to increased maintenance or operational requirements, increased costs due to reduced operating efficiency, and added administrative

costs. A refund is required to the extent the consideration received exceeds the just compensation permitted by the section.

The Commission is required to consider whether any transfer of contractual interests is likely to increase demand for imported refined petroleum products both at the time the Commission prescribes the rule required by this section and when the Commission determines whether to authorize a particular transfer of contractual interests.

If the natural gas is to be resold by the person to whom the contractual interests are to be transferred, the Commission must issue a certificate of public convenience and necessity for the transfer. In such cases, the certificate is to be issued by the Commission in accordance with the requirements of this section and those of section 7 of the Natural Gas Act. Specifically, the public convenience and necessity requirements of section 7 of the Natural Gas Act are made applicable to the certificate of public convenience and necessity required under this section.

The conference agreement renders unenforceable contractual provisions which could interfere with the transfer of contractual interests under this section. Such contractual provisions were included in contracts in order to protect the supplier of the natural gas from unanticipated jurisdictional consequences attaching to him under the Natural Gas Act by reason of a subsequent transfer of the gas. Because the conference substitute insulates such suppliers from jurisdictional consequences under the Natural Gas Act arising from transfers under this section, such contractual restrictions are not necessary to protect the interests of the gas supplier. Moreover, because the person acquiring contractual interests under this section is required to assume the obligations of the person transferring these interests, and the person transferring contractual interests is not relieved of any obligation not performed by the person acquiring such interests, the supplier of the natural gas has adequate recourse to assure enforcement of his contractual rights.

The person transferring contractual interests under this section may receive consideration for that transfer. However, such consideration may not exceed the level of "just compensation" established in the section. Just compensation when used with respect to the transferor means the maximum amount of consideration which does not exceed the amount by which the reasonable cost of using heavy petroleum fuel oil as a substitute exceeds the cost of natural gas under the contract. Costs associated with the use of heavy petroleum fuel oil as a substitute include allowances for amortization of undepreciated depreciable assets located on the premises of the facility if the assets were directly associated with the use of natural gas and are no longer usable in connection with the use of heavy petroleum fuel oil.

In the case of intrastate pipelines, the term, "just compensation" means an amount equal to any loss of revenue resulting from the transfer of contractual interests due to the reduction in transportation or distribution of natural gas if the lost revenue has not been offset by a reduction in expenses or by revenue derived from transportation or distribution of natural gas which would not have occurred if the contractual interests had not been transferred. Of course, such offset may be partially from a reduction in expenses and from new revenues. For example, transfer of contractual interests may result in a reduction in the use of the transportation facilities of the intrastate pipeline. Such would be the case where, after the transfer of contractual interests and by agreement of the parties, the natural gas is delivered by the intrastate pipeline at a point closer to the source of supply than the former delivery point and, therefore, the intrastate pipeline does not transport the gas as far. However, in some cases, the intrastate pipeline may be able to use the transportation capacity made available after the transfer of contractual interests to transport natural gas to other customers. The revenues from this latter transportation must be offset against any lost revenue resulting from the transfer of contractual interests.

The section provides for coordination with the Natural Gas Act and provides volume limitations on the amount of gas which a supplier may be required to supply pursuant to the transfer of contractual interests under the section.

In authorizing the transfer of contractual interests under this section, the conferees do not intend to relieve any party transferring such interests from performing any obligation under the contract. In addition, the conferees intend that the person acquiring contractual interests pursuant to this section shall assume all terms, conditions, and obligations existing under the contract. For example, contract provisions governing the place of delivery will remain in force and effect unless the parties agree otherwise.

It is contemplated by the conferees that the authority of this section will be utilized prior to the imposition of any prohibition on the use of natural gas by a major fuel-burning installation or electric utility under the Power Plant and Industrial Fuel Use Act of 1978. A companion provision in that act will facilitate the transfer of contractual interests in cases where the major fuel-burning installation or electric powerplant is prohibited from using natural gas under this act. For that reason, the time limitations contained in the original Senate provision have been deleted from the conference substitute.

Section 607. Emergency conversion of utilities and other facilities

The Senate amendment granted the Secretary of Energy authority to prohibit the use of natural gas as a fuel in any electric utility powerplant or major fuel-burning installation during a natural gas emergency declared pursuant to the Emergency Natural Gas Act of 1977. The provision applied to facilities which on September 1, 1977, or thereafter could burn petroleum products without damage to the facility or interference with production processes. The provision did not apply to facilities subject to a coal conversion order issued pursuant to the Energy Supply and Environmental Coordination Act of 1974. In addition, the exercise of authority under the Senate provision required a determination that the order would result in savings of significant quantities of natural gas before the termination of the natural gas emergency. The Secretary was required to find that petroleum products would be available to the electric utility powerplant or major fuel-burning installation prohibited from using natural gas.

The Secretary was authorized to permit facilities to use quantities of natural gas during the emergency period for serving peakloads and

for ignition, startup, testing, and flame stabilization. The Secretary was required to grant exemptions from the emergency prohibition orders to alleviate short-term air quality emergencies.

Judicial review of prohibition orders under the section was limited. No court had jurisdiction to grant interim injunctive relief deferring or staying implementation of a prohibition order issued under the section.

The Federal Energy Regulatory Commission was directed to prescribe rules providing for just compensation to all parties involved in the sale and transportation of natural gas prohibited from use by an order under the section. The level of just compensation was to be determined in the same manner as was provided in the companion provision of the Senate bill dealing with the voluntary conversion of industrial users of natural gas to heavy petroleum fuel.

The House bill had no comparable provision.

The conference substitute authorizes the President to declare a natural gas supply emergency based upon the same findings utilized for purposes of the declaration of a natural gas supply emergency under the Natural Gas Policy Act of 1978. The authority of this section is to be exercised after a declaration of an emergency under section 301 of the Natural Gas Policy Act of 1978 and after utilization of the emergency sales authority of section 302 of that Act, but before resort to the allocation authorities of section 303 of that Act. The limitations on the duration of any natural gas supply emergency declared under this section are identical to those contained in the Natural Gas Policy Act of 1978. During a natural gas supply emergency, the President is authorized to prohibit the burning of natural gas by major fuel-burning installations and electric powerplants.

Any such prohibition must be based upon a determination by the President that the powerplant or major fuel-burning installation had on September 1, 1977, the capability to burn petroleum products without damage to the facility or equipment and without interference with operational requirements. This limitation is not intended to encourage the President to issue prohibition orders inflexibly where, at the time of the order, alternative fuel burning capability no longer exists and, as a result, a prohibition order would cause severe hardship. In addition, the President must determine that significant quantities of natural gas which would otherwise be burned by the powerplant or installation can be made available to persons served by an interstate pipeline for use by such person in a high priority use. Finally, the President must determine that petroleum products will be available for use throughout the period any prohibition order under this section is in effect.

The section permits the President to authorize the continued burning of natural gas during the period in which any prohibition order is in effect, including the burning of natural gas by an electric powerplant to meet peakload requirements. Moreover, the President is required to exempt from prohibition orders the burning of natural gas for the necessary processes of ignition, startup, testing, and flame stabilization. The President is also required to exempt the burning of natural gas which the President determines is necessary to alleviate any im. —nt and substantial endangerment of human health within the meaning of section 303 of the Clean Air Act.

The conference substitute limits the jurisdiction of courts to grant injunctive relief to stay implementation of a prohibition order issued under the section. The U.S. District Court for the District of Columbia is the only court authorized to issue preliminary injunctive relief or temporary injunctive relief staying, in whole or in part, the implementation of any prohibition order issued under the section. The authority of the U.S. District Court for the District of Columbia may only be exercised after an opportunity for a hearing before the court has been afforded.

Once natural gas has been prohibited from use under this section, it is available for sale and may be the subject of a transfer of contractual interests under section 606 of the conference agreement. In applying the provisions of section 606 in such cases, the term "petroleum product" is substituted for the term "heavy petroleum fuel oil" in section 606 if the person subject to the prohibition order under this section demonstrates to the Federal Energy Regulatory Commission that the acquisition and use of heavy petroleum fuel oil is not technically or economically feasible. The practical effect of this provision is to broaden the application of section 606 in those instances where natural gas has been prohibited from use under this section. The conferees anticipate that this will facilitate the transfer of natural gas to another user during the period of the emergency. Moreover, under the emergency provisions of the Natural Gas Policy Act of 1978 provision is made for subjecting natural gas prohibited from use under this section to allocation under section 303 of that act.

Section 608. Natural gas transportation policies

The Senate amendment provided for a continuation of Federal Energy Regulatory policies encouraging the transportation of natural gas owned by the user of the gas. In addition, the Senate bill provided that if the Federal Energy Regulatory Commission approved the transportation of natural gas from reserves owned by the user, the Commission was required to approve the transportation for the life of reserves or such shorter period as provided in the contract between the user and the transporter of the natural gas. The section further provided that notwithstanding any other provision of law natural gas may be purchased by an end-user for a price in excess of any lawfully established ceiling price if the Commission determines that: (1) approval of the transaction is consistent with the public convenience and necessity; and (2) such natural gas will be consumed by the purchaser in a high priority use, as determined by the Commission. The purpose of the Senate provision was three-fold. First, the Senate provision would have codified in statute regulatory provisions of Commission Order No. 533 under which provision is made for the certification of transportation of natural gas in interstate commerce where the sale of the natural gas is not subject to the jurisdiction of the Commission because there is not a sale for resale, for example, the gas is sold to the user by the producer. However, the duration of transportation certificates issued under Order No. 533 has been limited. The second purpose of the Senate provision, therefore, was to require an extension of the duration of transportation approvals granted by the Federal Energy Regulatory Commission under the policies set forth in Order No. 533. Thirdly, the Senate provision was intended to exempt from all ceiling prices any purchase of natural gas by an end-user directly from the producer.

The conferees recognize that FPC Order 533 and the successor FERC program under Order No. 2 have proven to be of critical importance in helping industrial and commercial users of natural gas meet their high priority needs in times of curtailment. Because of the importance of these programs the conferees intend that if the FERC in any way modifies or changes Order No. 2 (the presently effective direct purchase program) it report to the Congress the nature of the change the basis and rationale for the change and the impact that such change will have on fuel supply to traditional users of these programs.

The conference substitute is based upon, but is more narrow in scope, than the Senate provision. The conference substitute amends section 7(c) of the Natural Gas Act to authorize the issuance of a certificate of public convenience and necessity by the Commission in the case of natural gas sold by the producer to the user and in case of natural gas produced by the user.

The provision is intended to remove any uncertainty which may exist regarding the basis for present Federal Energy Regulatory Commission policy regarding the transportation of user-owned natural gas by interstate pipelines. However, the conference substitute is not intended to require the Commission to issue a certificate of public convenience and necessity in any specific case. The question of whether to issue a certificate is left to the Commission based upon its determination of whether the transportation of the gas will serve the public convenience and necessity. In addition, limitations are not imposed on the exercise of this authority by the Commission other than the public convenience and necessity standard which is generally applicable to certification by the Commission of natural gas transportation.

Finally, the amendment is not intended to, and does not in any way, affect the applicability of ceiling prices, established under the Natural Gas Act, the Natural Gas Policy Act of 1978, or any other provision of law, to the sale of natural gas by a producer to a user.

Intention concerning certain accounting rules

No language appears in the conference report concerning section 141 of the Senate amendment.

Section 503 of the Energy Policy and Conservation Act (EPCA), entitled "Accounting Practices", requires "For purposes of developing a reliable energy data base related to the production of crude oil and natural gas, the Securities and Exchange Commission shall take such steps as may be necessary to assure the development and observance of accounting practices to be followed in the preparation of accounts by persons engaged, in whole or in part, in the production of crude oil or natural gas in the United States."

The Senate bill contained a section 141 that amended section 503 by adding a new subsection 503(d) which would have provided that this section of the EPCA is intended to apply only to the development of accounting practices required for the preparation of the reports to be filed with the Department of Energy for use in compiling a reliable energy data base. The amendment also provided that nothing contained in section 503 was to be construed to establish, or to affect the establishment of, generally accepted accounting principles for financial reporting purposes.

Senate and House conferees approve of the intent of section 141 that section 503 of EPCA does not compel nor prohibit the Securities and Exchange Commission from addressing public financial reporting in conjunction with the development of uniform accounting practices for reporting to the Department of Energy. However, the conferees regard section 141 as unnecessary.

In November 2, 1977, letter of response to Congressman John E. Moss concerning section 141, Chairman Harold M. Williams of the SEC reviewed the SEC's statutory authority to establish uniform accounting standards under the provisions of EPCA and the Federal securities laws. He noted the Commission's longstanding concern over the diversity of accounting and financial reporting practices in the oil and gas producing industry.

After noting the present role of the Financial Accounting Standards Board (FASB) in setting accounting standards, Chairman Williams stated:

> The Commission fully recognizes the widespread public interest in petroleum industry accounting practices and intends to scrutinize carefully any FASB pronouncement on financial reporting in that field. The Commission plans to solicit written public comment on the FASB's determination in this area, and, because of the importance of the issue, has also decided to hold public hearings on the matter early in 1978.

Chairman Williams said the SEC believed section 141 of H.R. 4018 was unnecessary, and might hamper efforts to establish uniform accounting standards for oil and gas producing companies.

The conferees expect that the SEC will consider in accordance with appropriate statutes all issues relating to changes in accounting by oil and gas producing companies, including the impact on exploration and development. The SEC has specifically stated in Securities Act Release No. 5861 (42 FR 44972) that it will consider the competitive impact of any changes in public financial reporting by producers of oil and gas.

Harley O. Staggers,
Thomas L. Ashley,
Al Ullman,
Richard Bolling,
Thomas S. Foley,
John D. Dingell,
Paul G. Rogers,
Bob Eckhardt,
Philip R. Sharp,
Anthony Moffett,
Henry S. Reuss,
James C. Corman,
Charles B. Rangel,
Managers on the Part of the House.

Henry M. Jackson,
J. Bennett Johnston,
John A. Durkin,
Floyd K. Haskell,
Dale Bumpers,
Howard M. Metzenbaum,
James A. McClure,
Pete V. Domenici,
Managers on the Part of the Senate.

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United States - Federal

TAB 2

Final Regulations Regarding Small Power Production and Cogeneration

Minnesota Power & Light Company
Mississippi Power Company
Mississippi Power & Light Company
Missouri Public Service Company
Mononganela Power Company
Montana-Dakota Utilities Company
Montana Power Company
Narragansett Electric Company
New Orleans Public Service, Inc.
Northern Indiana Public Service Company
Northern States Power Company
Northern States Power Company
Northwestern Public Service Company
Orange & Rockland Utilities
Portland General Electric Company
Potomac Edison Company
Potomac Electric Power Company
Public Service Company of Colorado
Public Service Company of Indiana
Public Service Company of New Hampshire
Public Service Company of New Mexico
Public Service Company of Oklahoma
Puget Sound Power and Light Company
Rochester Gas & Electric Corporation
St. Joseph Light & Power Company
South Carolina Electric & Gas Company
Southern Indiana Gas & Electric Company
Southwestern Public Service Company
Tampa Electric Company
Texas Utilities Electric Company
Tucson Electric Power Company
Union Electric Company
Union Light, Heat & Power Company
United Illuminating Company
Utah Power & Light Company
Washington Water Power Company
Western Massachusetts Electric Company
Western Power Division of Central Tel. & Util. Corporation
Wheeling Electric Company
Wisconsin Public Service Corporation

PUBLICLY-OWNED UTILITIES

Colorado Springs, Colorado
Eugene, Oregon
Fayetteville, North Carolina
Kansas City, Kansas
Lincoln, Nebraska
Lower Colorado River Authority
Modesto Irrigation District (CA)
Nebraska Public Power District
Omaha Public Power District
Power Authority of the State of New York
Public Utility District of Grant County (WA)
PUD No. 1 of Benton County (WA)
PUD No. 1 of Chelan County (WA)
PUD No. 1 of Clark County (WA)
PUD No. 1 of Cowlitz County (WA)
PUD No. 1 of Douglas County (WA)
PUD No. 1 of Snohomish County (WA)
Richmond, Indiana
Salt River Project (AZ)
San Antonio, Texas
Seattle, Washington

COOPERATIVELY-OWNED UTILITIES

Clay Electric Cooperative (FL)
Cobb Electric Membership Corporation (GA)
Flint Electric Membership Corporation (GA)
Green River Electric Corporation (KY)
Henderson-Union Rural Electric Cooperative Corporation (KY)
Jackson Electric Membership Corporation (GA)
Northern Virginia Electric Cooperative (VA)
Rappahannock Electric Cooperative (VA)
Sam Houston Electric Cooperative
Walton Electric Membership Cooperative
Withlacoochee River Electric Cooperative (FL)

[Order 353, 48 FR 55451, Dec. 13, 1983, as amended at 49 FR 4939, Feb. 9, 1984; 49 FR 23610, June 7, 1984]

PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION

Subpart A—General Provisions

Subpart B—Qualifying Cogeneration and Small Power Production Facilities

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AUTHORITY: Federal Power Act 16 U.S.C. 791a-824r (1982), as amended by Electric Consumers Protection Act of 1986, Pub. L. No. 99-495; Department of Energy Organization Act, 42 U.S.C. 7101-7352 (1982); EO 12009, 3 CFR 1978 Comp., p. 142; Independent Offices Appropriations Act, 31 U.S.C. 9701 (1982); Public Utility Regulatory Policies Act, 16 U.S.C. 2601-2645 (1982), as amended.

Subpart A—General Provisions

§ 292.101 Definitions.

(a) *General rule.* Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they have under PURPA, unless further defined in this part.

(b) *Definitions.* The following definitions apply for purposes of this part.

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of this part of the Commission's regulations.

(2) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(3) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(4) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

(7) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(8) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a

qualifying facility in addition to that which the facility generates itself.

(9) "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(10) "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(11) "Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.* Federal Power Act, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, E.O. 12009, 42 FR 46267)

[45 FR 12233, Feb. 25, 1980]

Subpart B—Qualifying Cogeneration and Small Power Production Facilities

AUTHORITY: Public Utility Regulatory Policies Act of 1978, (16 U.S.C. 2601, *et seq.*), Energy Supply and Environmental Coordination Act, (15 U.S.C. 791 *et seq.*), Federal Power Act, as amended, (16 U.S.C. 792, *et seq.*), Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*), E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, (15 U.S.C. 3301, *et seq.*).

§ 292.201 Scope.

This subpart applies to the criteria for and manner of becoming a qualifying small power production facility and a qualifying cogeneration facility under sections 3(17)(C) and 3(18)(B), respectively, of the Federal Power Act, as amended by section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

[45 FR 17972, Mar. 20, 1980]

§ 292.202 Definitions.

For purposes of this subpart:

(a) "Biomass" means any organic material not derived from fossil fuels;

(b) "Waste" means by-product materials other than biomass;

(c) "Cogeneration facility" means equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy;

(d) "Topping-cycle cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy;

(e) "Bottoming-cycle cogeneration facility" means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production;

(f) "Supplementary firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility;

(g) "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process;

(h) "Useful thermal energy output" of a topping-cycle cogeneration facility means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application;

(i) "Total energy output" of a topping-cycle cogeneration facility is the sum of the useful power output and useful thermal energy output;

(j) "Total energy input" means the total energy of all forms supplied from external sources;

(k) "Natural gas" means either natural gas unmixed, or any mixture of natural gas and artificial gas;

(l) "Oil" means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products; and

(m) Energy input in the case of energy in the form of natural gas or oil is to be measured by the lower heating value of the natural gas or oil.

(n) "Electric utility holding company" means a holding company, as defined in section 2(a)(7) of the Public

...tility Holding Company Act of 1935, 15 U.S.C. 79b(a)(7) which owns one or more electric utilities, as defined in section 2(a)(3) of that Act, 15 U.S.C 79b(a)(3), but does not include any holding company which is exempt by ...e or order adopted or issued pursu...nt to sections 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act ... 1935, 15 U.S.C. 79c(a)(3) or 79c(a)(5).

(o) "Utility geothermal small power production facility" means a small power production facility which uses geothermal energy as the primary energy resource and of which more than 50 percent is owned either:

(1) By an electric utility or utilities, electric utility holding company or companies, or any combination thereof.

(2) By any company 50 percent or more of the outstanding voting securities of which are directly or indirectly owned, controlled, or held with power to vote by an electric utility, electric utility holding company, or any combination thereof.

(p) "New dam or diversion" means a dam or diversion which requires, for the purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards of similar adjustable devices);

(q) "Substantial adverse effect on the environment" means a substantial alteration in the existing or potential use of, or a loss of, natural features, existing habitat, recreational uses, water quality, or other environmental resources. Substantial alteration of particular resource includes a change in the environment that substantially reduces the quality of the affected resources: and

(r) "Commitment of substantial monetary resources" means the expenditure of, or commitment to expend, at least 50 percent of the total cost of preparing an application for license or exemption for a hydroelectric project that is accepted for filing by the Commission pursuant to § 4.32(e) of this chapter. The total cost includes (but is not limited to) the cost of agency consultation, environmental studies, and engineering studies conducted pursuant to § 4.38 of this chapter, and the Commission's requirements for filing an application for license exemption.

Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, E.O. 12009, 42 FR 46267)

[45 FR 17972, Mar. 20, 1980, as amended at 45 FR 33958, May 21, 1980; 45 FR 66789, Oct. 8, 1980; Order 135, 46 FR 19231, Mar. 30, 1981; 46 FR 32239, June 22, 1981; Order 499, 53 FR 27002, July 18, 1988]

§ 292.203 General requirements for qualification.

(a) *Small power production facilities.* Except as provided in paragraph (c) of this section, a small power production facility is a qualifying facility if it:

(1) Meets the maximum size criteria specified in § 292.204(a);

(2) Meets the fuel use criteria specified in § 292.204(b); and

(3) Meets the ownership criteria specified in § 292.206.

(b) *Cogeneration facilities.* A cogeneration facility, including any diesel and dual-fuel cogeneration facility, is a qualifying facility if it:

(1) Meets any applicable operating and efficiency standards specified in § 292.205 (a) and (b); and

(2) Meets the ownership criteria specified in § 292.206.

(c) *Hydroelectric small power production facilities located at a new dam or diversion.* (1) Except as provided in paragraph (c)(2) of this section, a hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion (as that term is defined in § 292.202(p)) is a qualifying facility if it meets the requirements of:

(i) Paragraph (a) of this section; and

(ii) Section 292.208.

(2) *Moratorium.*—(i) *General rule.* Except as provided in paragraph (c)(2)(ii) of this section, a hydroelectric small power production facility that impounds or diverts the water of

a natural watercourse is not a qualifying facility if the moratorium described in section 8(e) of the Electric Consumers Protection Act of 1986 (ECPA), Pub. L. No. 99-495, is in effect. The moratorium applies to a license or an exemption issued on or after October 16, 1986. The moratorium will end at the expiration of the first full session of Congress following the session during which the Commission reports to Congress on the results of the study required by section 8(d) of ECPA.

(ii) *Exemption.* A hydroelectric small power production facility is exempt from the moratorium and can be a qualifying facility if it:

(A) Meets the requirements in paragraph (c)(1) of this section; and

(B) Qualifies for one of the exceptions in §§ 292.209 or 292.210.

[45 FR 17972, Mar. 20, 1980, as amended by Order 70-E, 46 FR 33027, June 26, 1981; 52 FR 5280, Feb. 20, 1987; 52 FR 9161, Mar. 23, 1987; Order 478, 52 FR 28467, July 30, 1987; Order 499, 53 FR 27002, July 18, 1988]

§ 292.204 Criteria for qualifying small power production facilities.

(a) *Size of the facility*—(1) *Maximum size.* The power production capacity of the facility for which qualification is sought, together with the capacity of any other facilities which use the same energy resource, are owned by the same person, and are located at the same site, may not exceed 80 megawatts.

(2) *Method of calculation.* (i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.

(ii) For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility.

(3) *Waiver.* The Commission may modify the application of paragraph (a)(2) of this section, for good cause.

(b) *Fuel use.* (1) (i) The primary energy source of the facility must be biomass, waste, renewable resources, geothermal resources, or any combination thereof, and 75 percent or more of the total energy input must be from these sources.

(ii) Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.

(2) Use of oil, natural gas, and coal by a facility may not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar year period.

(Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15, U.S.C. 791, *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

[45 FR 17972, Mar. 20, 1980, as amended by Order 135, 46 FR 19231, Mar. 30, 1981]

§ 292.205 Criteria for qualifying cogeneration facilities.

(a) *Operating and efficiency standards for topping-cycle facilities*—(1) *Operating standard.* For any topping-cycle cogeneration facility, the useful thermal energy output of the facility must, during any calendar year period be no less than 5 percent of the total energy output.

(2) *Efficiency standard.* (i) For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal energy output, during any calendar year period, must:

(A) Subject to paragraph (a)(2)(i)(B) of this section be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or

(B) If the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.

(ii) For any topping-cycle cogeneration facility not subject to paragraph (a)(2)(i) of this section there is no efficiency standard.

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(b) *Efficiency standards for bottoming-cycle facilities.* (1) For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility must, during any calendar year period, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.

(2) For any bottoming-cycle cogeneration facility not covered by paragraph (b)(1) of this section, there is no efficiency standard.

(c) *Waiver.* The Commission may waive any of the requirements of paragraphs (a) and (b) of this section upon a showing that the facility will produce significant energy savings.

[45 FR 17972, Mar. 20, 1980, as amended by Order 478, 52 FR 28467, July 30, 1987]

§ 292.206 Ownership criteria.

(a) *General rule.* A cogeneration facility or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities).

(b) *Ownership test.* For purposes of this section, a cogeneration or small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power, if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company, or companies, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or electric utility holding company has an ownership interest of a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or electric utility holding company.

(c) *Exceptions.* For purposes of this section a company shall not be considered to be an "electric utility" company if it:

(1) Is a subsidiary of an electric utility holding company which is exempt by rule or order adopted or issued pursuant to section 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79c(a)(3) 79c(a)(5); or

(2) Is declared not to be an electric utility company by rule or order of the Securities and Exchange Commission pursuant to section 2(a)(3)(A) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3)(A).

[45 FR 17972, Mar. 20, 1980, as amended by Order 70-B, 45 FR 52780, Aug. 8, 1980; Order 70-D, 46 FR 11253, Feb. 6, 1981]

§ 292.207 Procedures for obtaining qualifying status.

(a) *Qualification.* (1) A small power production facility or cogeneration facility which meets the criteria for qualification set forth in § 292.203 is a qualifying facility.

(2) The owner or operator of any facility qualifying under this paragraph shall furnish notice to the Commission providing the information set forth in paragraphs (b)(2) (i) through (iv) of this section.

(b) *Optional procedure*—(1) *Application for Commission certification.* Pursuant to the provisions of this paragraph, the owner or operator of the facility may file with this Commission an application for Commission certification that the facility is a qualifying facility.

(2) *General contents of application.* The application must be accompanied by the fee prescribed in § 381.505 of this chapter and must contain the following information:

(i) The name and address of the applicant and location of the facility;

(ii) A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility;

(iii) The primary energy source used or to be used by the facility;

(iv) The power production capacity of the facility; and

(v) The percentage of ownership by any electric utility or by any electric utility holding company, or by any person owned by either.

(3) *Additional application requirements for small power production facilities.* An application by a small power producer for Commission certi-

fication shall contain the following additional information:

(i) The location of the facility in relation to any other small power production facilities located within one mile of the facility, owned by the applicant which use the same energy source; and

(ii) Information identifying any planned usage of natural gas, oil or coal.

(4) *Additional application requirements for cogeneration facilities.* An application by a cogenerator for Commission certification shall contain the following additional information:

(i) A description of the cogeneration system, including whether the facility is a topping or bottoming cycle and sufficient information to determine that any applicable requirements under § 292.205 will be met; and

(ii) The date installation of the facility began or will begin.

(5) *Commission action.* Within 90 days of the filing of an application, the Commission shall issue an order granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify the specific requirements which were not met. If no order is issued within 90 days of the filing of the complete application, it shall be deemed to have been granted.

(6) *Notice.* (i) Applications for certification filed under this paragraph shall include a copy of a notice of the request for certification for publication in the FEDERAL REGISTER. The notice shall state the applicant's name, the date of the application, and a brief description of the facility for which qualification is sought. This description shall include:

(A) A statement indicating whether such facility is a small power production facility or a cogeneration facility;

(B) The primary energy source used or to be used by the facility;

(C) The power production capacity of the facility; and

(D) The location of the facility.

(ii) The notice shall be in the following form:

(Name of Applicant)
Docket No. QF-

NOTICE OF APPLICATION FOR COMMISSION CERTIFICATION OF QUALIFYING STATUS OF A (SMALL POWER PRODUCTION) COGENERATION) FACILITY

On (date application was filed), (name and address of applicant) filed with the Federal Energy Regulatory Commission an application to be certified as a qualifying (small power production) cogeneration) facility pursuant to § 292.207 of the Commission's rules.

[Brief description of the facility].

Any person desiring to be heard or objecting to the granting of qualifying status should file a petiton to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§385.209 and 385.214 of this chapter. All such petitions or protests must be filed within 30 days after the date of publication of this notice and must be served on the applicant. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

(c) *Notice requirements for facilities of 500 kW or more.* An electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kW or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b) of this section.

(d) *Revocation of qualifying status.* (1) The Commission may revoke the qualifying status of a qualifying facility which has been certified under this section if such facility fails to comply with any of the statements contained in its application for Commission certification.

(2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status.

[45 FR 17972, Mar. 20, 1980, as amended by Order 70-A, 45 FR 33603, May 20, 1980; Order 70-B, 45 FR 52780, Aug. 8, 1980; Order 225, 47 FR 19058, May 3, 1982; Order

§ 292.208 Special requirements for hydroelectric small power production facilities located at a new dam or diversion.

(a) A hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion (as that term is defined in § 292.202(p)) is a qualifying facility only if it meets the requirements of:

(1) Paragraph (b) of this section;

(2) Section 292.203(c); and

(3) Part 4 of this chapter.

(b) A hydroelectric small power production described in paragraph (a) is a qualifying facility only if:

(1) The Commission finds, at the time it issues the license or exemption, that the project will not have a substantial adverse effect on the environment (as that term is defined in § 292.202(q)), including recreation and water quality;

(2) The Commission finds, at the time the application for the license or exemption is accepted for filing under § 4.32 of this chapter, that the project is not located on any segment of a natural watercourse which:

(i) Is included, or designated for potential inclusion in, a State or National wild and scenic river system; or

(ii) The State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural or scenic attributes which would be adversely affected by hydroelectric development; and

(3) The project meets the terms and conditions set by the appropriate fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act.

(c) For the Commission to make the findings in paragraph (b) of this section an applicant must:

(1) Comply with the applicable hydroelectric licensing requirements in Part 4 of this chapter, including:

(i) Completing the pre-filing consultation process under § 4.38 of this chapter, including performing any environmental studies which may be required under §§ 4.38(b)(2)(i)(D) through (F) of this chapter; and

the requirements of § 4.41 [illegible] of this chapter, regardless of project size.

(2) State whether the project is located on any segment of a natural watercourse which:

(i) Is included in or designated for potential inclusion in:

(A) The National Wild and Scenic River System (28 U.S.C. 1271-1278 (1982)); or

(B) A State wild and scenic river system;

(ii) Crosses an area designated or recommended for designation under the Wilderness Act (16 U.S.C. 1132) as:

(A) A wilderness area; or

(B) Wilderness study area; or

(iii) The State, either by or pursuant to an act of the State legislature, has determined to possess unique, natural, recreational, cultural, or scenic attributes that would be adversely affected by hydroelectric development.

(d) If the project is located on any segment of a natural watercourse that meets any of the conditions in paragraph (c)(2) of this section, the applicant must provide the following information in its application:

(1) The date on which the natural watercourse was protected;

(2) The statutory authority under which the natural watercourse was protected; and

(3) The Federal or state agency, or political subdivision of the state, that is in charge of administering the natural watercourse.

[Order 499, 53 FR 27003, July 18, 1988]

§ 292.209 Exceptions from requirements for hydroelectric small power production facilities located at a new dam or diversion.

(a) The requirements in §§ 292.208(b)(1) through (3) do not apply if:

(1) An application for license or exemption is filed for a project located at a Government dam, as defined in section 3(10) of the Federal Power Act, at which non-Federal hydroelectric development is permissible; or

(2) An application for license or exemption was filed and accepted before October 16, 1986.

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(b) The requirements in §§ 292.208(b) (1) and (3) do not apply if an application for license or exemption was filed before October 16, 1986, and is accepted for filing by the Commission before October 16, 1989.

(c) The requirements in § 292.208(b)(3) do not apply to an applicant for license or exemption if:

(1) The applicant files a petition pursuant to § 292.210; and

(2) The Commission grants the petition.

(d) Any application covered by paragraphs (a), (b), or (c) of this section is excepted from the moratorium imposed by section 8(e) of the Electric Consumers Protection Act of 1986, Pub. L. No. 99-495.

[Order 499, 53 FR 27003, July 18, 1988]

§ 292.210 Petition alleging commitment of substantial monetary resources before October 16, 1986.

(a) An applicant covered by § 292.203(c) whose application for license or exemption was filed on or after October 16, 1986, but before April 16, 1988, may file a petition for exception from the requirement in § 292.208(b)(3) and the moratorium described in § 292.203(c)(2). The petition must show that prior to October 16, 1986, the applicant committed substantial monetary resources (as that term is defined in § 292.202(r)) to the development of the project.

(b) Subject to rebuttal under paragraph (d)(7)(ii) of this section, a showing of the commitment of substantial monetary resources will be presumed if the applicant held a preliminary permit for the project and had completed environmental consultations pursuant to § 4.38 of this chapter before October 16, 1986.

(c) *Time of filing petition.*—(1) *General rule.* Except as provided in paragraph (c)(2) of this section, the applicant must:

(i) File the petition with the application for license or exemption; or

(ii) Submit with the application for license or exemption a request for an extension of time, not to exceed 90 days or April 16, 1988, whichever occurs first, in which to file the petition.

(2) *Exception.* If the application for license or exemption was filed on or after October 16, 1986, but before March 23, 1987, the petition must have been filed by June 22, 1987.

(d) *Filing requirements.* A petition filed under this section must include the following information or refer to the pages in the application for license or exemption where it can be found:

(1) A certificate of service, conforming to the requirements set out in § 385.2010(h) of this chapter, certifying that the applicant has served the petition on the Federal and State agencies required to be consulted by the applicant pursuant to § 4.38 of this chapter;

(2) Documentation of any issued preliminary permits for the project;

(3) An itemized statement of the total costs expended on the application;

(4) An itemized schedule of costs the applicant expended, or committed to be expended, before October 16, 1986, on the application, accompanied by supporting documentation including but not limited to:

(i) Dated invoices for maps, surveys, supplies, geophysical and geotechnical services, engineering services, legal services, document reproduction, and other items related to the preparation of the application, and

(ii) Written contracts and other written documentation demonstrating a commitment made before October 16, 1986, to expend monetary resources on the preparation of the application, together with evidence that those monetary resources were actually expended; and

(5) Correspondence or other documentation to support the items listed in paragraphs (d)(3) and (d)(4) of this section to show that the expenses presented were directly related to the preparation of the application.

(6) The applicant must include in its total cost statement and in its schedule of the costs expended or committed to be expended before October 16, 1986, the value of services that were performed by the applicant itself instead of contracted out.

(7)(i) If the applicant held a preliminary permit for the project and had completed pre-filing consultation

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suant to § 4.38 of this chapter prior to October 16, 1986, the applicant may, instead of submitting the information listed in paragraphs (d)(3), (d)(4), and (d)(5) of this section, submit a statement identifying the preliminary permit by project number.

(ii) If any interested person objects pursuant to § 385.211 of this chapter) to the presumption in paragraph (b) of this section, the applicant must supply the information listed in paragraphs (d)(3), (d)(4), and (d)(5) of this section.

(8) If the application is deficient pursuant to § 4.32(e) of this chapter, the applicant must include with the information correcting those deficiencies a statement of the costs expended to make the corrections.

(e) *Processing of petition.* (1) The Commission will issue a notice of the petition filed under this section and publish the notice in the FEDERAL REGISTER. The petition will be available for inspection and copying during regular business hours in the Public Reference Room maintained by the Division of Public Information.

(2) *Comments on the petition.* The Commission will provide the public 45 days from the date the notice of the petition is issued to submit comments. The applicant for license or exemption has 15 days after the expiration of the public comment period to respond to the comments filed with the Commission.

(3) *Commission action on petition.* The Director of the Office of Hydropower Licensing will determine whether or not the applicant for license or exemption has made the showing required under this section.

[Order 499, 53 FR 27003, July 18, 1988]

§ 292.211 Petition for initial determination on whether a project has a substantial adverse effect on the environment (AEE petition).

(a) An applicant that has filed a petition under § 292.210 may also file an AEE petition with the Commission for an initial determination on whether the project satisfies the requirement that it has no substantial adverse effect on the environment as specified in § 292.208(b)(1).

(b) The filing of the AEE petition does not relieve the applicant of the filing requirements of § 292.208(c).

(c) The Commission will act on the AEE petition only if the Commission has granted the applicant's commitment of resources petition under § 292.210.

(d) *Time of filing petition.* The applicant may file the AEE petition with the application for license or exemption or at any time before the Commission issues the license or exemption.

(e) *Contents of petition.* The AEE petition must identify the project and request that the Commission make an initial determination on the adverse environmental effects requirements in § 292.208(b)(1).

(f) The Director of the Office of Hydropower Licensing will make the initial determination on the AEE petition. In making this determination, the Director will consider the following:

(1) Any proposed mitigative measures;

(2) The consistency of the proposal with local, regional, and national resource plans and programs;

(3) The mandatory terms and conditions of fish and wildlife agencies under section 210(j) of PURPA, or section 30(c) of the Federal Power Act; or the recommended terms and conditions of fish a wildlife agencies under Section 10(j) of the Federal Power Act, whichever is appropriate; and

(4) Any other information which the Director believes is relevant to consider.

(g) *Initial finding on the petition.* The Director of the Office of Hydropower Licensing will make the initial determination on the AEE petition after the close of the public notice period for the accepted application. If the Director's initial determination finds:

(1) No substantial adverse effect on the environment, the Commission must wait at least 45 days before making a final determination that the project satisfies the requirements of § 292.208(b)(1).

(2) A substantial adverse effect on the environment, the applicant may file, within 90 days of the initial find-

ing that the project does not satisfy the requirements in § 292.208(b)(1), proposed measures to mitigate the adverse environmental effects found.

(3)(i) The Commission will provide written notice of the Director's initial finding on the petition to the applicant, to the federal and state agencies that the applicant must consult under § 4.38 of this chapter and to any intervenors in the proceeding.

(ii) The Commission will publish notice of the Director's initial finding in the FEDERAL REGISTER.

(h) *Notice and Comment on the Mitigative measures.* (1) The Commission will issue notice of the mitigative measures filed by an applicant under paragraph (g)(2) of this section and will publish the notice in the FEDERAL REGISTER. The mitigative measures will be on file and available for inspection or copying during regular business hours in the Public Reference Room maintained by the Division of Public Information;

(2) The Commission will provide the State and interested persons within 90 days from the date the notice is issued to review and submit comments on the mitigative measures. The applicant for license or exemption has 15 days after the expiration of the public comment period to respond to the comments filed with the Commission.

(i) *Material amendments to application.* The proposed mitigative measures filed under paragraph (g)(2) of this section will not be considered a material amendment to the application unless the Commission finds that the proposed measures are unnecessary to, or exceed the scope of, mitigating substantial adverse effects. If the Commission finds the proposed mitigative measures constitute a material amendment, the application will be considered filed with the Commission on the date on which the applicant filed the proposed mitigative measures, and all other provisions of § 4.35(a) of this chapter will apply.

(j) *Final determination on the petition.* The Commission will make a final determination on the petition at the time the Commission issues a license or exemption for the project.

(k) *Presumption* (1) If, between the Commission's initial and final findings on the AEE petition, the State does not take any action under § 292.208(b)(2), the failure to take action can be the basis for a presumption that there is not substantial adverse effect on the environment (as that term is defined in § 292.202(q)).

(2) If the presumption in paragraph (k)(1) of this section comes into effect, it:

(i) Is only available for those adverse effects related to the natural, recreational, cultural, or scenic attributes of the environment;

(ii) Can only operate during the time between the Commission's initial and final findings on the AEE petition; and

(iii) Has no affect on the Commission's independent obligation to find that the project will not have a substantial adverse effect on the environment under § 292.208(b)(1).

(3) The presumption in paragraph (k)(1) of this section does not take effect if the State, the Commission or an interested person demonstrates that the State has acted to protect the natural watercourse under § 292.208(b)(2).

(4) The presumption in paragraph (k)(1) of this section can be rebutted if:

(i) The Commission determines that the project will have a substantial adverse effect on the environment related to the environmental attributes listed in paragraph (k)(2)(i) of this section; or

(ii) Any interested person, including a State, demonstrates that the project will have a substantial adverse effect on the environment related to the environmental attributes listed in paragraph (k)(2)(i) of this section.

[Order 499, 53 FR 27004, July 18, 1988, as amended at Order 499-A, 53 FR 40724, Oct. 18, 1988]

BEST AVAILABLE DOCUMENT

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

AUTHORITY: Public Utility Regulatory Policies Act of 1978. 16 U.S.C. 2601 *et seq.*, Energy Supply and Environmental Coordination Act. 15 U.S.C. 791 *et seq.* Federal Power Act. 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act. 42 U.S.C. 7101 *et seq.*, E.O. 12009. 42 FR 46267.

SOURCE: 45 FR 12234, Feb. 25, 1980, unless otherwise noted.

§ 292.301 Scope.

(a) *Applicability.* This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

§ 292.302 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until June 30, 1982.

(b) *General rule.* To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(c) *Special rule for small electric utilities.* (1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) *Substitution of alternative method.* (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) *State Review.* (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

[45 FR 12234, Feb. 25, 1980; 45 FR 24126, Apr. 9, 1980]

§ 292.303 Electric utility obligations under this subpart.

(a) *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, any energy and capacity requested by the qualifying facility.

(c) *Obligation to interconnect.* (1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(d) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission

(e) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

§ 292.304 Rates for purchases.

(a) *Rates for purchases.* (1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(a) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) *Relationship to avoided costs.* (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) *Standard rates for purchases.* (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) *Periods during which purchases not required.* (1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.305 Rates for sales.

(a) *General rules.* (1) Rates for sales

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional Services to be Provided to Qualifying Facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully

coordinated with scheduled outages of the utility's facilities.

§ 292.306 **Interconnection costs.**

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

§ 292.307 **System emergencies.**

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.308 **Standards for operating reliability.**

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

Subpart D—Implementation

AUTHORITY: Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, E.O. 12009, 42 FR 46267.

SOURCE: 45 FR 12236, Feb. 25, 1980, unless otherwise noted.

§ 292.401 **Implementation by State regulatory authorities and nonregulated electric utilities.**

(a) *State regulatory authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(b) *Nonregulated electric utilities.* Not later than one year after these rules take effect, each nonregulated electric utility shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(c) *Reporting requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonreguated electric utility shall file with the Commission a report describing the manner in which it will mplement Subpart C other than § 292.302 thereof).

§ 292.402 Implementation of certain reporting requirements.

Any electric utility which fails to comply with the requirements of § 292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

§ 292.403 Waivers.

(a) *State regulatory authority and nonregulated electric utility waivers.* Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of Subpart C (other than § 292.302 thereof).

(b) *Commission action.* The Commission will grant such a wavier only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of Subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

Subpart E—[Reserved]

Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to qualifying facilities, other than those described in paragraph (b) of this section.

(b) *Exclusion.* This section does not apply to a qualifying small power production facility with a power production capacity which exceeds 30 megawatts, if such facility uses any primary energy source other than geothermal resources.

(c) *General rule.* Any qualifying facility described in paragraph (a) of this section shall be exempt from all sections of the Federal Power Act except:

(1) Section 1-18, and 21-30;

(2) Sections 202(c), 210, 211, and 212

(3) Sections 305(c); and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (c)(1), (2) and (3) of this section.

(Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

[Order 135, 46 FR 19232, Mar. 30, 1981]

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) of this section or a utility geothermal small power production facility shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(c) *Exemption from certain State law and regulation.* (1) Any qualifying facility shall be exempted (except as provided in paragraph (c)(2)) of this section from State law or regulation respecting:

(i) The rates of electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State law and regulation implementing Subpart C.

(3) Upon request of a State regulatory authority or nonregulated electric

...ility the Commission may consider a limitation on the exemptions specified in paragraph (c)(1) of this section.

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

[45 FR 12237, Feb. 25, 1980, as amended by Order 135, 46 FR 19232, Mar. 30, 1981]

PART 294—PROCEDURES FOR SHORTAGES OF ELECTRIC ENERGY AND CAPACITY UNDER SECTION 206 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

AUTHORITY: Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 3117; Federal Power Act, 16 U.S.C. 792 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; E.O. 12009, 42 FR 46267; Administrative Procedure Act, 5 U.S.C. 553.

§ 294.101 Shortages of electric energy and capacity.

(a) *Definition of shortages of electric energy and capacity.* For purposes of this section, the term "anticipated shortages of electric or energy" means:

(1) Any situation anticipated to occur in which the generating and bulk purchased power capability of a public utility will not be sufficient to meet its anticipated demand plus appropriate reserve margins and this shortage would affect the utility's capability adequately to supply electric services to its firm power wholesale customers; or

(2) Any situation anticipated to occur in which the energy supply capability of a public utility is not sufficient to meet its customers' energy requirements and this shortage would affect the utility's capability adequately to supply electric services to its firm power wholesale customers.

(b) *Accommodation of shortages.* (1) Each public utility now serving firm power wholesale customers, shall submit a brief statement indicating how it would accommodate any shortages of electric energy or capacity affecting its firm power wholesale customers.

(2) This statement shall:

(i) Describe how the utility would assure that direct and indirect customers are treated without undue prejudice or disadvantage; and

(ii) It shall also identify any agreement, law, or regulation which might impair the utility's ability to accommodate such a shortage.

(3) Each utility shall file a copy of its statement with any appropriate State regulatory agency and all firm power wholesale customers.

(4) If a plan for accommodating any shortages of electric energy or capacity affecting its firm power wholesale customers as described in the brief statement submitted pursuant to paragraph (b)(1) of this section is modified, the utility must submit to the Commission and the persons described in paragraph (b)(3) of this section within 15 days of any such modification, a supplemental statement informing the Commission of those modifications.

(c) *Reporting requirements.* Each public utility shall immediately report to the Commission, to any State regulatory authority and to firm power wholesale customers, any anticipated shortage of electric energy or capacity. The report shall include the following information:

(1) The nature and projected duration of the anticipated capacity or energy supply shortage;

(2) A list showing all firm power wholesale customers affected or likely to be affected by the anticipated shortage;

(3) Procedures for accommodating the shortage, if different from those described in paragraph (b) of this section;

(4) An estimate of the effects (reduced power and energy usage) of use of these procedures upon the utility's wholesale and retail customers; and

(5) The name, title, address and telephone number of an officer or employee of the utility who may be contacted for further information regarding the shortage and planned actions of the utility.

(d) *Reports to other government entities.* Any report filed with another governmental entity that contains the information that must be reported under this part may be filed to comply with this part.

(e) *Number of copies.* Any public utility that files under this part must provide an original of any filing and at least two exact copies to this Commission and one copy to any state regulatory authority and firm power wholesale customers, unless otherwise required by the Commission.

[44 FR 37502, June 27, 1979, as amended at 47 FR 20297, May 12, 1982; Order 401, 49 FR 39538, Oct. 9, 1984; Order 401-A, 54 FR 41087, Oct. 5, 1989]

United States - Federal

TAB 3

Rulemakings on Cogeneration and Small Power Production (see table of contents therein)

Federal Energy Regulatory Commission

Rulemakings on
Cogeneration and Small Power Productio

May, 1981

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INTRODUCTION

The broad purpose of the Public Utility Regulatory Policies Act of 1978 (PURPA), one of the five parts of the National Energy Act, is to encourage conservation of energy and efficient use of energy resources by public utilities. One means of achieving this end is to encourage production of electric power by cogeneration and by small power producers. It is estimated that these technologies could save the nation 1.75 million barrels of oil a day by 1995.

Cogeneration is the combined production of power and useful heat by the sequential use of energy from one fuel source -- the reject heat of one process becomes the energy input into a subsequent process. Approximately three-fourths of the energy used to raise steam for industrial uses actually performs useful work; the rest is wasted if not captured for cogeneration.

Small power producers are defined as facilities generating not more than 80 megawatts of electric power and which employ renewable resources such as water power, solar energy, wind energy or geothermal energy, or biomass or waste as a primary fuel.

Until recently, a lack of economic incentives and certain regulatory and institutional barriers have limited development of these technologies. PURPA authorized the Federal Energy Regulatory Commission to provide appropriate incentives and to remove these barriers.

In the past, a developer of cogeneration or small power production facilities faced three major regulatory and economic obstacles. First, utilities were not generally required to purchase the electric power generated by these facilities, and were not required by law to pay appropriate rates for this power. Second, some utilities charged discriminatorily high rates for backup power required by cogenerators and small power producers. Finally, a cogenerator or small power producer providing electricity to a utility grid might be subjected to the same state and Federal regulation as an electric utility. Sections 201 and 210 of PURPA are designed to remove these obstacles and encourage cogeneration and small power production.

The Commission issued proposed regulations implementing sections 201 and 210 in 1979. After a series of public hearings, analysis of the extensive written comments received and consultation with state public utility regulatory commissions, final rules were issued under Section 210 on February 19, 1980 and section 201 on March 13, 1980.

FERC staff has prepared an assessment of the effects that development of cogeneration and small power production may have on the environment. The likely effects were found to be insignificant except in the case of cogeneration by diesel engines; the staff is now preparing an environmental impact statement on the effects of diesel cogeneration.

This booklet, which contains copies of the FERC's rules and other documents on cogeneration and small power production, is intended to provide a basic understanding of the issues involved and the procedures developed by the Commission in formulating these regulations.

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Federal Register Notices
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The Staff Discussion Paper sets forth many of the issues facing the Commission in developing regulations under Section 210 of PURPA. It was issued prior to the Notice of Proposed Rulemakings..

Order No. 69 (Docket No. RM79-55) contains the rules implementing Section 210 of PURPA. It establishes rates for sales of electric power between qualifying cogeneration and small power production facilities and electric utilities, and establishes exemptions for qualifying facilities from state and federal regulations governing electric utilities.

Order No. 70 (Docket No. RM79-54) establishes criteria and procedures by which cogeneration or small power production facilities can qualify for the rates and exemptions set forth in Order No. 69. It also establishes the eligibility of qualifying cogeneration facilities for an exemption from incremental pricing of natural gas contained in the Natural Gas Policy Act of 1978.

Order No. 49 (Docket No. RM79-14) contains the Commission's rules implementing the incremental pricing provisions under Title II of the Natural Gas Policy Act of 1978. An exemption was established in this rule for qualifying cogeneration facilties, as defined in the Commission's rules implementing Section 201 of PURPA. The Commission issued an "Interim Rule for Qualification of Gas-Fired Cogeneration Facilities for Purposes of the Incremental Pricing Program" in Docket No. RM79-54 which was later incorporated into Order No. 70.

Docket Nos. RM79-54 and RM79-55
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ENVIRONMENTAL FINDINGS: Small Power Production and Cogeneration Facilities--Environmental Findings; No Significant Impact and Notice of Intent to Prepare Environmental Impact Statement
(Issued March 31, 1980, Published April 8, 1980)

"Environmental Findings; No Significant Impact and Notice of Intent To Prepare Environmental Impact Statement" (Docket Nos. RM79-54 and RM79-55) contains the Commission's environmental assessment of the effect of these regulations. With the exception of new diesel cogeneration facilities, these rules will not significantly affect the environment. The Commission gave notice that it intends to prepare an environmental impact statement evaluating the effects of the increased use of diesel cogeneration that would result from qualification of that technology.

Docket No. RM79-54:
Order No. 70-A
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AMENDMENT TO FINAL RULE: Small Power Production and Cogeneration Facilities; Amendment to Final Rule Providing that Applications for Commission Certification of Qualifying Status Contain a Notice for Publication in the Federal Register
(Issued May 5, 1980, Published May 20, 1980)

Order No. 70-A (Docket No. RM79-54) provides that applications for Commission certification of qualifying status pursuant to the rules implementing Section 201 of PURPA contain a notice for publication in the Federal Register.

Docket Nos. RM79-54 and RM79-55:
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AMENDMENT TO ORDER NOS. 69 AND 70: Small Power Production Order Granting in Part and Denying in Part Rehearing of Orders Nos. 69 and 70, and Amending Regulations
(Issued May 15, 1980, Published May 21, 1980)

The Commission's "Order Granting in Part and Denying in Part Rehearing of Orders Nos. 69 and 70 (Docket Nos. RM79-55 and 54) and Amending Regulations", and the "Amendment to Final Rule Providing that Applications for Commission Certification of Qualifying Status Contain a Notice for Publication in the Federal Register" contain clarification and minor revisions of Orders Nos. 69 and 70.

Docket No. RM79-54:
Order No. 70-B
Page 120

AMENDMENT TO ORDER NO. 70: Order Granting in Part and Denying in Part Rehearing of Order No. 70, and Amending Regulations
(Issued August 4, 1980, Published August 8, 1980)

Order No. 70-B (Docket No. RM79-54) permits gas utility holding companies to own qualifying cogeneration and small power production facilities.

Docket No. RM79-54:
Order No. 70-C
Page 122

AMENDMENT TO ORDER NO. 70: Order Granting Rehearing of Order No. 70-B and Amending Regulations
(Issued September 26, 1980, Published October 8, 1980)

Order No. 70-C (Docket No RM79-54) permits electric utility holding companies found by the Securities and Exchange Commission to be "exempt holding companies" under Sections 3(a)(3) and 3(a)(5) of the Public Utility Holding Company Act to own qualifying cogeneration and small power production facilities.

Docket No. RM79-54:
Order No. 70-D
Page 124

AMENDMENT TO ORDER NO. 70: Order Amending Regulations
(Issued January 28, 1981, Published February 6, 1981)

Order No. 70-D (Docket No. RM79-54) enables certain "electric utilities" which are not "primarily engaged in the generation or sale of electric energy" to own up to 100 percent of a qualifying facility.

Docket No. RM80-62:
Order No. 104
Page 127

FINAL RULE: Regulations Exempting Mechanical Cogeneration Facilities from the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978
(Issued October 23, 1980, Published October 30, 1980)

Order No. 104 (Docket No. RM80-62) contains rules allowing mechanical cogeneration facilities to obtain exemption from the incremental pricing provisions of the Natural Gas Policy Act of 1978.

Docket No. RM81-2:
Order No. 135
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FINAL RULE: Eligibility, Rates and Exemptions for Qualifying and Utility-Owned Geothermal Small Power Production Facilities
(Issued March 23, 1981, Published March 30, 1981)

Order No. 135 implements the Energy Security Act amendments to the Federal Power Act and the Public Utility Regulatory Policies Act of 1978 concerning geothermal small power production facilities. Except with respect to the Public Utility Holding Company Act, this rule-making implements the Energy Security Act only as it relates to geothermal small power production facilities of which a utility owns less than 50 percent.

FOR FURTHER INFORMATION CONTACT:

Glenn Berger or Michael Kessler: Office of the General Counsel
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426
(202) 357-8033

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[18 CFR Part 292]

[Docket No. RM79-55]

Staff Paper Discussing Commission Responsibilities To Establish Rules Regarding Rates and Exemptions for Qualifying Cogeneration and Small Power Production Facilities Pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Staff paper issued, by direction of the Commission, for comment.

SUMMARY: This paper discusses the Commission's responsibilities to issue final rules pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) relating to the rates at which power should be exchanged between qualifying cogeneration and small power production facilities and electric utilities and the criteria under which certain qualifying facilities should be exempt from certain State and federal regulations.

DATE: Comments are due by August 1, 1979.

ADDRESS: All comments to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM79-55).

FOR FURTHER INFORMATION CONTACT:
Adam Wenner, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 275-0422.
Robert Cackowski, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-4778.

June 28, 1979.

Memorandum to: The Commission.

From: John B. O'Sullivan, Chief Advisory Counsel; Robert E. Cackowski, Deputy Director, OEPR.

Subject: Section 210 of the Public Utility Regulatory Policies Act of 1978, Concerning Cogeneration and Small Power Production Facilities.

This memorandum is intended to serve as a discussion paper on Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The memorandum will describe this section of the law, our preliminary view as to how the law might actually work, and some problems that might develop in implementation.

Introduction

Under the Federal Power Act (FPA), sales from cogenerators and small power producers to a public utility (as defined in Part II of the FPA) would, so long as the electricity might make its way into the bulk power transmission grid, make the cogenerator or small power producer itself a public utility. In other words, by virtue of its sale for resale in interstate commerce, the cogenerator or small power producer would itself become a public utility under Part II of the Power Act. Prior to the enactment of PURPA, the FERC was not authorized to abstain, in whole or in part, from exercising its jurisdiction over such cogenerator-public utilities and small power producer-public utilities. The prospect of plenary regulation unquestionably acted as a powerful disincentive to the generation and sale of surplus power by such facilities, particularly where the owner was an industrial concern unfamiliar with the arcane intricacies of utility regulation. It should be noted that sales of supplemental or back-up power to such cogenerators and small power producers by the local public utility would in most instances be a retail sale regulated by the State.

In Sections 201 and 210 of PURPA, Congress has grappled with both the split jurisdiction and the disincentive to certain desirable kinds of electric generation imposed by the rigid jurisdictional provisions of the FPA, as well as with allegations that some utilities were not dealing in good faith with certain existing or proposed

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cogenerators and small power producers. The PURPA scheme, though certainly novel in the context of traditional utility regulation and probably complex to administer, is a logical approach to solving the problems with which Congress was concerned.

Section 201 of PURPA generally defines a "qualifying small power production facility," "qualifying small power producer," "qualifying cogeneration facility," and "qualifying cogenerator." The Commission is to establish by rule the detailed criteria for qualifying facilities of both types. Generally, a qualifying small power production facility (SPPF) can only use biomass, waste, renewable resources (including hydro from existing dams), or a combination thereof, as a primary energy source; and, together with other facilities at the same site, cannot have a capacity greater than 80 megawatts. A cogeneration facility is defined as a facility which produces both electricity and steam or some other useful form of energy, such as heat. There is no size limit for qualifying cogeneration facilities. A qualifying facility of either type must be "owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)."[1]

Having delineated by Section 201 and the Commission rules promulgated thereunder the class with which it was dealing, the Congress provided certain substantial benefits of qualification in Section 210. Broadly stated, these benefits are the following:

(1) Electric utilities (defined as any person, State agency or Federal agency which sells electric energy)[2] can be compelled to buy power from qualifying facilities. The price applied to such required purchases must be just and reasonable to the customers of the purchasing utility and in the public interest. The Commission may not prescribe a price for such sales that "exceeds the incremental cost to the electric utility of alternative electric energy." The price shall not discriminate against the selling qualifying cogenerator or small power producer.

(2) Utilities can be compelled to sell to qualifying facilities. The price applied to such required sales shall be just and reasonable and in the public interest and shall not discriminate against the qualifying cogenerator or small power producer.

(3) Qualifying small power production facilities whose size does not exceed 30 megawatts of capacity and all qualifying cogeneration facilities may be exempted in whole or in part by Commission rule from the Federal Power Act, from the Public Utility Holding Company Act, and from State laws and regulations respecting the financial or organizational regulation of public utilities, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

Rules embodying these principles are to be issued by the Commission within one year after enactment, viz. by November 8, 1979. The law provides that the State regulatory authorities and nonregulated utilities are to implement the Commission's rules within a year after they are prescribed.

As this bare-bones description of the statute may or may not make apparent, there is the potential, if not a requirement, for a fundamental reordering of the traditional dual regulatory scheme as it applies to certain cogenerators and small power producers.[3] Whereas before the FERC had jurisdiction over sales from such power producers for resale in interstate commerce, while the states regulated retail sales, PURPA provides for FERC rules governing *both* transactions. And the states, which have not had jurisdiction over sales for resale in interstate commerce, will in all likelihood carry out the day-to-day regulation of such sales where they involve qualifying facilities (QFs) in addition to continuing to regulate all retail sales, including sales to QFs. However, the regulation of transactions involving QFs may well be conducted under the state regulations implementing the FERC's rules promulgated pursuant to Section 210, rather than under State laws. In other words, the requirement that the States and nonregulated utilities implement the FERC's rules, together with the FERC's authority to exempt QFs from some or all of Parts II and III of the FPA and from State law could (and almost certainly will) result in the delegation-by-exemption to the States of both old and new FERC regulatory responsibilities.

The second major departure from or reordering of traditional utility regulation inherent in the Section 210 scheme is a consequence of the Congress's intention to avoid the treatment of qualifying cogenerators and small power producers as utilities, where such treatment is a disincentive to these kinds of generation. Traditional regulation has, naturally, focused on the seller. For the most part, regulators regulate the public utility, not its customers. There is plentiful precedent for a requirement to sell (Sections 202(b) and (c) of the FPA, virtually all State law concerning service to retail customers), but almost none for required purchases of the sort provided for in Section 210. Similarly, under conventional regulation, the seller's rates are subject to regulatory approval, the test of the reasonableness of which is the seller's costs. Here, because of the effort to relieve some generators of the burdens of regulation, Congress has established a scheme in which the primary reference point for determining the price for a sale from a QF to a utility is not the seller's cost but the buyer's avoided cost. Indeed, the Congress has specifically instructed FERC that QFs are not to be subjected to the same scrutiny and requirements for organization and reporting as regular utilities; and the authority to grant exemptions is the device which Congress has given the Commission not only to avoid such regulation on its own part, but also to ensure that once the Federal preemption of such regulation is removed, the States do not begin to regulate QFs as utilities.

All this is not to say that there is a lack of precedent for the Commission, State regulators, and nonregulated utilities to look to in implementing Section 210 of PURPA. Many utilities have experience with their own cogeneration (primarily those that provide district heat steam service.) With regard to the sale from a utility to a qualifying facility, the primary model is conventional State-regulated retail sales, though in some instances partial requirements or interchange wholesale rates provide a better basis of comparison. With regard to the sale from a qualifying facility to an electric utility, wholesale rates probably provide the best analogy in most cases, particularly where a relationship between a utility and a number of

[1] However, a utility or a number of utilities may participate in the ownership of a facility; and nothing in the statute bars a utility from operating a qualifying facility. In fact, a utility operating such a facility which it did not own would become a "qualifying cogenerator" or "qualifying small power producer."

[2] The definition of electric utility applicable to Section 210 is that which appears in Title I of PURPA (and which includes the Federal power marketing agencies), not the Title II definition (which does not). The Title II definition (from PURPA § 201) has become a part of the Federal Power Act (specifically, § 3(22)), and thus applies to the parts of PURPA which amend the Power Act. Section 3(4) of PURPA establishes the definition to be applied to those parts of PURPA which, like Section 210, are not made a part of the Federal Power Act.

[3] Except where a precise point of statutory construction is being discussed, we will use the terms "cogenerator" and "small power producer", interchangeably with, respectively, "cogeneration facility" and "small power production facility".

qualifying facilities begins to resemble a power pool. Useful information may also be gleaned from the not-uncommon arrangement whereby a utility purchases power from an industrial cogenerator or self-generator. A number of States have already begun work on rules concerning cogenerators and a few are quite far along this road, and this also can provide substantial guidance.

Nonetheless, it is fair to say that in many instances the transactions between utilities and those who will qualify under Section 201 have in the past fallen into a gap between the FPC/FERC and State regulators. It is certain that the terms under which these transactions take place vary enormously from utility to utility and region to region. In the following more detailed discussion, we will not attempt to provide in all instances a single correct or even preferred approach to implementation. Because of regional differences in circumstances, the enormous range of characteristics as to both loads and power production likely to be exhibited by various qualifying facilities, and simple uncertainty as to what the law means or what the best approach to a problem is, we will often merely list some apparent alternatives. By this we do not mean to imply that the Commission will in every case ultimately be faced with making a choice of a single approach from among a number of alternatives. It is quite likely that the Commission will want to leave the States and the nonregulated utilities flexibility for experimentation and accommodation of special circumstances on a number of these matters.

With respect to the nonregulated utilities, consideration will be given as to the necessity of a separate set of rules from that applicable to the State commissions due to the fact that the nonregulated electric utility will be both the entity responsible for implementing the Commission's rules and the utility directly dealing with the cogenerator or small power producer.

Exemptions

Section 210 directs the Commission within a year of enactment to prescribe rules exempting small power production facilities with no more than 30 megawatts of capacity and all cogenerators from part or all of the Federal Power Act, from the Public Utility Holding Company Act, and from State laws and regulations respecting the rates or respecting the financial or organizational regulation of utilities, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. Small power production facilities of greater than 30 megawatt capacity using biomass exclusively as a primary energy source may be exempted from the Holding Company Act and State laws, but not from the Federal Power Act.[4] Under 210(e)(3), no QF can be exempted from Part I of the Power Act. Sections 210, 211 and 212 of the Power Act (added by Sections 202, 203 and 204 of PURPA, and having to do with interconnection and wheeling), and State laws and regulations implementing the Commission's rules promulgated pursuant to Section 210.

It is clear from the Conference Report that Congress intended the Commission to make liberal use of its exemption authority:

The conferees wish to make clear that cogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications * * *. The conferees expect that the establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production.

Although we have not conducted an exhaustive survey, there is good reason to believe that many if not most State laws provide for regulation of cogeneration and small power production facilities as utilities. These State laws have been rendered ineffective in most instances because of the FPA preemption of regulation of sales for resale in interstate commerce. Were the Commission to exempt QFs from FPA regulation, but not from State regulation, the State laws would then take effect, frustrating the intent of Congress that QFs not be subjected to the same scrutiny and organizational requirements as utilities. It would be difficult to maintain that the Federal preemption continued even after the Commission exempted QFs from the FPA (that is, that the area was deliberately left vacant, and that the States could not then occupy the area) if the Commission chose not to exercise its authority to exempt from State regulation. Therefore, it seems likely that in the great majority of cases where the Commission provides an exemption from the FPA it will also want to provide substantial exemptions from State law.[5]

Basically, there are two approaches that can be taken to the State law exemption. The first, which is both more precise and more cumbersome, is to analyze the laws of each State and specify the exemptions to be provided citing sections of State law and regulations. We do not recommend this approach, except possibly for the non-contiguous states and territories and contiguous areas not hooked into the interstate grid (primarily parts of Texas). The second approach is to make a broad prescription exempting from any and all provisions of State law and regulations as would conflict with the State's implementation of the Commission's rules under Section 210. This approach, while it may lead to some disputes which the Commission will have to become involved in, has the advantages of simplicity, administrative ease, and permanence (i.e., the language of the exemption would not have to be changed every time a State changed its laws or regulations).

While the proper course seems obvious with regard to Federal and State rate regulation and the requirements for filing voluminous reports concerning operating, cost and revenue data,[6] the matter of exemption from provisions of the FPA concerning financing and related matters and from the Public Utility

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[4] Thus the Commission is not authorized to exempt small power production facilities of 30 to 80 megawatt capacity from any of those laws, with the exception of biomass users who still cannot be exempted from the FPA. As a technical matter, this would leave in place two conflicting regulatory schemes covering this group: Section 210 pricing, and traditional Federal Power Act regulation of the QSPP who becomes a Part II public utility by virtue of a wholesale sale into interstate commerce. The Conference Report resolves this for the most part by instructing the Commission to use Section 210 pricing for this group. Left unresolved are two questions: (1) What will be the effect of State regulation on small power producers of greater than 30 megawatts who are making sales for resale but not into interstate commerce (such as in Alaska, Hawaii, Puerto Rico and most of Texas)? and (2) Should the Commission exempt biomass small power producers in these areas from State regulation, where the consequence is that they will not be regulated at all?

[5] Note that the Commission does not have the authority to exempt cogenerators from State regulation as a steam utility. This fact may have somewhat disparate consequences (assuming that some cogenerators may be interested in selling steam), since some States do not regulate steam sales, some do so only if the seller is already a utility, and some do so whether or not the seller is an electric utility.

A quite different and somewhat anomalous situation involving preemption may arise if a State has by statute directed the State regulatory authority not to regulate cogenerators. The most reasonable approach to this situation would seem to be to treat the State law as consistent with Section 210 of PURPA, in that (as the introduction points out) it is really the utility as buyer and seller that is regulated.

[6] Though it is worth noting that some exemptions here will affect the data provided to the Energy Information Administration, where EIA's authority is derived from the Federal Power Act.

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Holding Company Act is not nearly so clear. Pending consultation with the Staff of the Securities and Exchange Commission, we will not attempt an exhaustive analysis of this subject. However, as a rule of thumb it seems reasonable to provide that where a firm is subjected to more stringent regulation than other companies simply because it is engaged in electric utility business, those requirements should be eased through exemptions for QFs; but where a certain kind of regulation is applied to electric companies under the FPA or the Public Utility Holding Company Act, and applied in equal measure to non-utilities under other statutes enforced by the S.E.C., the argument for exemption is not nearly so strong. An example of the former, utility-only kind of provision is the requirement that a holding company show that its subsidiaries are or are capable of being operated on an integrated basis. In this case, we think exemption warranted. By contrast, exemption from certain security acquisition and interlocking directorship provisions may not be warranted.

As the Conference Report indicates, some participation by one or more utilities in the ownership of qualifying facilities may be permitted by the Commission's Section 201 rules. However, an exemption granted to a facility under 210(e) would not serve to release a utility or holding company participating in some way in a QFs ownership from any other unrelated obligations it may have under the law, since Section 210 permits the exemption of the QF, not of a parent (or grandparent). (In this context, we take this to mean that where a facility is granted an exemption, participation in the ownership of the facility will not give rise to a particular legal obligation that would have otherwise attached). We interpret 210(e) as giving the Commission sufficient flexibility to grant an exemption such that a non-utility parent is relieved of certain obligations while a utility or holding company participating in the same project is not. Again, the test for an exemption is whether it is "necessary to encourage cogeneration and small power production."

Finally, it should be noted that the exemption of QFs from traditional utility-type regulation, as specifically discussed in the Conference Report, may have the effect of making QFs eligible for a 20% energy investment tax credit. A recent change (March 1979) in Treasury Department regulations permits the exclusion from "public utility property" of property used in the business of the furnishing or sale of electric energy if the rates are not subject to regulation that fixes a rate of return on investment. Prior to the change, any rate regulation made property subject thereto (and involved in the furnishing or sale of electric energy) public utility property. Being thus excluded from public utility property, qualifying facilities have an opportunity to come within the definition of "alternative energy property," and thus qualify for the 20% ITC.

In fact, it may well be that even small power production facilities too large to be exempted may be eligible for the higher tax credit, due to the Conference Report's instruction to set the prices for sales by these SPPFs to utilities "in accordance with the requirements of" Section 210 rather than by "utility-type regulation."

Interconnection

Section 210 requires that utilities buy from and sell to QFs. It does not, however, explicitly provide authority to the Commission to order any interconnection necessary to effect the required transaction. The question thus arises as to whether there is inherent in section 210 of PURPA the authority to order such interconnections, or whether QFs must use Sections 210 and 212 of the FPA (added by Sections 202 and 204 of PURPA) to gain interconnection.

Perhaps the strongest argument against the finding that there is an interconnection authority within the cogeneration section is that the interconnection section itself explicitly lists qualifying cogenerators and small power producers as among those who are eligible to make an application. (By contrast, the next section, dealing with wheeling, does not confer eligibility on QFs.) Moreover, the requirement under Sections 210 and 212 of the FPA that the party seeking interconnection must show himself to be ready, willing and able to pay the resulting costs, and the companion criterion that the interconnection order not be issued if it would result in a reasonably ascertainable uncompensated economic loss for any electric utility, might be seen as consistent with the statement in the Conference Report that the cogeneration section was not to be applied so as to force a utility's customers to subsidize a qualifying facility.

Although this argument is respectable, we think it the better view that the requirement to interconnect is subsumed within the requirement to buy and sell. To hold otherwise would mean that Congress intended to have qualifying facilities go through an extended and expensive proceeding simply to gain interconnection, contrary to the entire thrust of Sections 201 and 210.

These sections evince the clear Congressional intent to encourage development of these desirable forms of generation, and to have the commercial development of these facilities proceed expeditiously. In other words, Congress has already made the judgment that these kinds of facilities serve one of the purposes of the Act as set out in Section 101, *viz.* "the optimization of the efficiency of use of facilities and resources by electric utilities", and it would be both redundant and unduly burdensome to have the sponsors of individual facilities show in an evidentiary hearing (FPA § 210(b)(2)) that their project in particular would serve this end (or one of the other related goals established as criteria for an interconnection order in § 210(c)(2)). After all, the purpose of an interconnection application, whether under Section 202 or 210 of the FPA, is to secure service, whether emergency or otherwise; and Section 210 of PURPA establishes the entitlement of a QF to service from the interconnected utility. In effect, the proponents of the view that a QF must apply under Sections 210 and 212 of the FPA have the burden of showing that Congress intended interconnection and the entitlement to buy and sell be denied to a QF which is unable to make the showings required by those sections even though a previously-interconnected customer installing qualifying facilities would not have to do so.

This is not to say that all of the protections that Congress has given the target of an interconnection application in Sections 210 and 212 of the FPA are necessarily absent from Section 210 of PURPA. The Conference Report on Section 210 states that customers of utilities are not to be compelled to subsidize QFs, and this principle would seem to bear on the question of who pays the costs of interconnection as well as on the per-unit price to be paid for energy. On the other hand, the conference Report includes a prescription against "unreasonable rate structure impediments, such as *unreasonable hook up charges.*" (emphasis added) This provides another argument in favor of reading Section 210 as including interconnection authority, since the elaborate cost determination required under Sections 210 and 212 of the FPA is redundant if the costs of interconnection are viewed simply as a feature of the rate structure with the

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charge therefor based on the cost of the utility.

Reliability

Section 210(a) states that the rules requiring utilities to buy from and sell to QFs "shall include provisions respecting minimum reliability of [QFs] (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies."

This statutory language raises the question of whether the Commission *must* prescribe minimum reliability requirements for qualifying facilities selling to utilities.

Section 201 specifically mentions reliability as one of the factors the Commission may take into account in establishing the criteria for qualifying small power production facilities. (It is not mentioned in the parallel language concerning co-generators.) We read Section 201 as permitting but not requiring the Commission to establish a minimum standard for the reliability of small power producers. Whether one agrees with this interpretation or believes that the Commission must establish such a threshold, the question remains as to why the Congress included provisions concerning reliability in Section 210 for both kinds of facilities after having mentioned it in Section 201 as to one kind but not the other.

Of course, the degree of reliability and/or availability can and should be reflected in the price for electric service, whether a utility or a QF is the seller. Putting a price tag on a particular degree of reliability is practically an everday exercise for utilities and regulatory agencies. Put another way, then, the question is whether the Congress intended the Commission to establish rules on QF reliability under Section 210 that went beyond a requirement that differences in reliability be fully reflected in prices.

The Congress evinced a clear concern that utility customers not be required by the Commission's Section 210 rules to subsidize QFs. The 210(a) language concerning reliability might well have been intended to prevent indirect subsidies resulting either from frivolous or otherwise uneconomical interconnections (with the costs borne by the utility's customers) or from a diminution in the quality of service rendered by a utility due to an interconnected facility's disruption of a utility's operations.

Elsewhere in this memorandum we have recommended that the incremental costs of interconnection or reinforcement of a utility's distribution and transmission facilities (*i.e.* those costs which the utility would not have incurred in securing the same power from an alternative source, or in providing service to the qualifying facility if the facility did not have its own generation) should be borne by the QF. So long as facilities can be devised which are sufficient to protect the utility from disruption of its operations by a QF—and our present understanding is that such protective devices can always be provided— and the QF rather than the utility bears the costs of these facilities, then no such indirect subsidy would occur.

Our analysis thus leads us to the conclusion that every incidence of a QF's reliability (or unreliability) can be accounted for through prices. If this conclusion withstands the test of public comment, we would recommend to the Commission that it establish no minimum reliability standard pursuant to Section 210(a), but that it make full provision for the consequences of varying degrees of reliability in the rules on pricing.

It is reasonable to expect many different kinds of facilities to be covered by and become involved with Section 210, ranging from large, self-sufficient and previously-isolated industrial generators to small, experimental and somewhat exotic facilities. The reliability that these different kinds of QFs will need from utilities and will be able to offer utilities will run the gamut. The needed services may vary from something comparable to a typical firm retail sale to more sophisticated pooling and interconnection arrangements. Similarly the service offered by QFs to electric utilities will range from dump or interruptible energy to firm power sales, *i.e.*, a reliable substitute for capacity that would otherwise be installed by the utility.

It is difficult, if not impossible, to predict what kinds of facilities will present themselves to any given utility. Thus it appears that the approach that would best satisfy the statutory mandate to encourage cogeneration and certain types of small power production is to require all electric utilities to offer to buy and sell services providing a complete range of reliability,[7] with the proviso that in each instance the price will have to be calculated so as to satisfy the other provisions of section 210, including the principle that utility customers not be compelled to subsidize QFs.

This requirement that electric utilities offer a complete menu of services (at appropriate prices) should not be too great a hardship, at least for public utilities, since between their wholesale and retail rate schedules most now offer a broad range of services, including firm all requirements, standby, interruptible and emergency services (though many do not offer what may be the closest parallel in many instances, partial requirements service).

With regard to emergency sales from QFs to utilities, we would note that congenerators and small power producers can be the subject of an order under Section 202(c) of the FPA to provide energy if the Economic Regulatory Adminisration determines that an emergency exists. Absent the declaration of a 202(c) emergency, we would recommend leaving the terms of emergency availability to the negotiations of the parties, subject only to the rule recommended in the preceding paragraphs.

Sales from Utilities to Qualifying Facilities

Section 210(c) of PURPA provides that:

> The rules prescribed under Subsection (a) [which requires, *inter alia*, that utilities sell to QFs] shall insure that in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale—
>
> (1) shall be just and reasonable and in the public interest, and
>
> (2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.
>
> * * * * *

This statutory language is similar to the language contained in Sections 205 and 206 of the FPA and is probably similar to many of the State statutes with respect to utility regulation. Such language thus permits traditional ratemaking concepts with respect to the sales to QFs.

In most instances, it would appear appropriate for the proposed rules to require the States to apply their standard ratemaking concepts in establishing rates for the QFs to the extent possible, even where there is a significant difference between FERC's approach and that of a state. That is, in most instances the test as to whether a QF is being discriminated against *as a utility customer* will be made by comparing the QF to other retail customers of the utility. For example,

[7] We do not mean to imply by this that qualifying facilities could rely on this requirement to secure a higher degree of reliability than firm, full requirements customers, or secure for themselves a higher priority than other customers with similar end-uses under a short- or long-term emergency load-shedding plan.

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Although California might choose to exempt qualifying facilities from having to pay a share of the subsidy for lifeline rates required of other industrial customers, there does not seem to be a valid argument that the failure to exempt QFs is discriminatory, since the QFs would simply be treated like others in the class to which they would belong if they did not have their own generation. Similarly, there seems no reason why any steps taken under Title I of PURPA with respect to such matters as time of day rates should not also apply to QFs.

In determining the rates to QFs, one of the first issues likely to arise is whether all or some QFs should be served as a separate rate class or included among a more general class such as the industrial or large power customers. It would appear that latitude should be given in the rules to permit inclusion of QFs within a general rate class to the extent that the load characteristics permit. This may be the most practical approach where the number of potential QFs is relatively small and might not warrant the costs associated with developing a separate rate class. Similarly, latitude should be given to permit classification as a separate rate class if the number of potential customers is large and/or the load characteristics are likely to impose substantially different costs on the system from the general rate class. These general problems of customer classification will of course become less important to the extent the states move to time-of-day rates.

Two major problems arise in the area of customer class assignment due to a shortage of good data. First, a majority of utilities do not have good load data even for their major retail customer classes, and in a number of states neither the utilities nor their regulatory agencies set rates based upon a class cost of service calculation. (The load data problem will be resolved over the long haul for the larger electric utilities by Section 133 of PURPA, which requires the collection of cost and load information by customer class.) Second, even where utilities have good data for their existing major classes, estimates as to the service requirements of QFs, and thus the costs imposed on the utility (determined to a considerable extent by the outages of the customer's own generation and the type of standby service the customer wants), may not at first rise above the level of speculation. The second problem may be eased substantially over the short run if QFs and utilities can agree to contracts specifying the services the utility will be called on to provide. However, where the two parties cannot reach this kind of agreement (such as where a cogenerator is unsure of its own production and is not willing to contract for interruptible service from the utility for any part of its potential load), the problem remains.

Whether or not a QF agrees to specific contractual levels of service, and whether a QF is assigned to an existing customer class, has a custom-designed individual rate, or is placed in a special class (or one among several special classes) for QFs, the first problem does not seem susceptible of precise solution over the short term. It would seem difficult to declare with any confidence that rates for a particular customer or class of customers is just and reasonable if there is no approved way of determining the customer's cost responsibility; and it would seem to be impossible to determine with any precision whether or not a proposed rate were discriminatory when one does not know the cost of serving the class or classes whose rates the QF's rates are to be compared to. Indeed, it may even be difficult to determine whether or not some or all QFs should be grouped with a particular class or subclass when little is known about the cost and load characteristics of the class.

Since some cogenerators and small power producers may have operations similar to those of utilities with generating facilities, the rules should provide sufficient latitude to permit interconnection and coordination agreements or partial requirement agreements similar to those subject to this Commission's jurisdiction. This would provide contractually specified operating criteria and would allow a full range of services including the sharing of mutual benefits of diversity and coordination. In fact, wholesale rates may provide some makeshift basis for determining what retail rates are appropriate for QFs where little is known about retail loads and costs by class.

Where large numbers of existing customers are converting their operations from those of a full requirements customer to that of a cogenerator or small power producer, such conversion may significantly alter total system loads and costs and almost certainly alter the outcome of a class cost allocation. To the extent that the conversion increases the total system costs from what they would otherwise be, or, more likely, leaves roughly the same fixed costs to be spread over fewer units sold, the rules should permit consideration of this fact by the states in determining the rates for such customers and the remaining customers on the system.* This situation might become a significant factor in determining whether the rates are in the "public interest" as required by Section 210(c). (The effect on system loads and costs is also an important consideration in determining the rates for power purchased by the utility from the cogenerator or small power producer, as discussed later.)

One of the most often discussed problems of rates for cogenerators or small power producers is the charge for backup or standby service. Here, the question of what costs the customer(s) imposes on the utility, and thus what the appropriate rate is, essentially turns on three factors: first, the reliability of the customer's generating equipment, or, put another way, the likelihood that the customer will be unable to supply part or all of his own electricity needs; second, the extent to which the customer will call on the utility to make up such a deficiency; and third, the degree of coincidence between such outages and the utility's peak demands. Cogenerators generally argue for lower backup charges based on the fact that they are unlikely to experience outages all at the same time, whereas the utilities argue for higher charges due to lack of ability to predict the time or duration of an outage since the operation of the facilities is outside a utility control. In part, this argument comes down to prudent utility planning for meeting loads that are potentially volatile and are dependent in part on the maintenance practices of the non-utility operators.

Where there is not a retail class of customers for backup service, with a rate based upon group outage probabilities, or perhaps even where there is such a class, latitude should be given in the rules to permit groups of qualifying cogenerators or small power producers to contractually "pool" their operations among themselves to minimize the potential cost impact on the utilities. By first pooling among themselves, QFs might facilitate individual contractual dealings with utilities and reduce its attendant costs. Pooled QFs certainly could make a much stronger argument that probabilistic analysis should be used in determining the backup charges, and based on the coordination the analysis would show a lowered probability of coincident outages. Such "pooling" might include arrangements such as coordinated maintenance or mutual

*We do not mean to imply that the entire shortfall, if there be any, should be imposed on QFs. rather, we merely suggest that it does not seem inappropriate for QFs to bear some share of the burden.

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other sources, will take into account the reliability of the power supplied by the cogenerator or small power producer by reason of any legally enforcible obligation of such cogenerator or small power producer to supply firm power to the utility.

The references to "additions to capacity" and to obligations "to supply firm power" (the rates for which, in our experience, always include a capacity component) bring us to the conclusion that the better reading of Section 210 is that capacity payments to QFs can be required under certain circumstances; and that, indeed, a utility's refusal to make payments based in part on avoided capacity payments could be discriminatory.

The paragraph from the Conference cited above also has a message for QFs, however: utilities make capacity payments to each other where firm commitments to make and hold capacity available are involved. A cogenerator or small power producer which is unwilling or unable to make such a commitment and to achieve a high degree of reliability, is not enabling the purchasing utility to avoid the costs of construction or a capacity purchase, and thus these costs do not serve to increase the ceiling on the rates the QF can demand.

In short, the statute provides an upper limit on the price for a capacity purchase (including an energy rate component) at the alternative capacity and energy costs avoided due to such purchase. Among other things, the duration of the purchase, the planning horizon of the utility and the capacity and load situation of the utility will affect such alternative costs. Generation expansion models (which discount the future costs of alternatives to a common present value) may be used to quantify such costs once the magnitude and duration of capacity purchases are known. The composition of such studies would vary depending on the answers to certain questions: Will utilities be required to pay now on a discounted basis for capacity not yet needed? Will capacity sales have priority over dump energy? How far into the future must utilities commit to buy, both as to initiation and duration of the sale?

Interruptible (by the QF) energy sales can be priced a number of ways. For example, a split-the-savings concept similar to economy energy purchases in existing interchange agreements could be employed.[10] Although economy energy is normally priced on an hour-by-hour, transaction-by-transaction basis, consideration should be given to a more general approach with lower administrative costs such as estimated monthly or annual savings. The difference between the cogenerator's out-of-pocket cost and the utility's out-of-pocket cost avoided as a result of the transaction would be shared on an equitable basis between the QF and the utility. Rather than the typical equal split of the savings, latitude should be given to permit negotiations resulting in a greater proportion of the savings going to the cogenerator in order to encourage cogeneration as intended by the statute. So long as the price is less than the alternative cost to the utility, the buying utility's ratepayers benefit from such transactions, and the statute would seem to be satisfied.[11] Such an approach may seem to depart from the Conferees' directive not to scrutinize the costs of QFs as though they were utilities. However, this approach should not generally produce a substantial burden on the QF since in most cases the QF should have calcualted its marginal energy cost to determine if it can afford to sell to a utility, particularly at times when the utility's marginal running cost is low. In any case, the statute does not prohibit all inquiry into a QF's costs, and this approach would not require a determination of a reasonable rate of return to the QF, which appears to be the conferees' primary concern.

Where a utility is a member of a centrally dispatched pool, the pool's marginal running cost will probably be the appropriate measure of the ceiling for energy rates. Similarly, if a pool has coordinated planning for capacity additions, the pool's method of sharing those costs should be considered, and in some instances utilized, in determining a pool member's avoided capacity costs.

As in the case of purchases by QFs, the rules for sales by QFs should permit sufficient latitude to allow "contractual pooling" among QFs to "firm up" capacity available to utilities. Such pooling could permit such things as coordinated scheduling for maintenance which would increase the assured availability of capacity to the utility. Although this may assure increased generating capacity, further consideration should be given to the potential impact on transmission costs of such arrangements.

Section 210(b) also requires that the rates for the purchases by the electric utilities not discriminate against QFs. It is not clear whether the statute only bars discrimination against QFs as a class, or whether it would also bar discrimination among QFs. If the latter, this may create some practical problems in administration. Since the price to be paid for the purchases by the utility is dependent, in part, on the utility's avoided costs, and these costs will vary over time and with the number and magnitude of cogeneration arrangements previously entered into, the rates paid will probably have to differ from one arrangement to another depending on when they were entered into and what future costs are being avoided. Further, as with multiple simultaneous interchange transactions, some priority among QFs may have to be established to determine which is viewed as displacing the utility's highest cost alternative power. Some vintaging arrangement or consistent formulary approach to the computation of the costs avoided may be considered in the rule for the purpose of determining whether the rates discriminate among qualifying facilities.

Under certain circumstances it may be desirable to allow a cogenerator or small power producer to sell all its output to a utility and, at the same time, purchase all its needs from the utility. Specifically, where a utility needs additional capacity, and one of its customers can build and operate a new generator more cheaply than the utility can, it would be in everyone's interest for the QF to build the unit. However, if the utility's embedded cost-based rates even after it built the new plant are lower than the incremental cost of power from the new facility the QF would have built, then it would be in the QF's interest to let the utility build the plant and supply its needs. Put another way, if a QF were prohibited from buying from and selling to a utility simultaneously, it would be compelled to "buy" from itself at its marginal cost. Where this is lower than the utility's

[10] This analogy may be of some assistance where a State's fuel adjustment clause rules, like the FERC's, permit a complete pass-through to customers of the cost of economy purchases where the cost is lower than that of the displaced fuel.

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Under certain circumstances it may be desirable to allow a cogenerator or small power producer to sell all its output to a utility and, at the same time, purchase all its needs from the utility. Specifically, where a utility needs additional capacity, and one of its customers can build and operate a new generator more cheaply than the utility can, it would be in everyone's interest for the QF to build the unit. However, if the utility's embedded cost-based rates even after it built the new plant are lower than the incremental cost of power from the new facility the QF would have built, then it would be in the QF's interest to let the utility build the plant and supply its needs. Put another way, if a QF were prohibited from buying from and selling to a utility simultaneously, it would be compelled to "buy" from itself at its marginal cost. Where this is lower than the utility's

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rate based on average embedded cost, then the QF would still build the facility, as it should in this situation; but where the utility's rate is lower than the QF's marginal cost, the wise firm would allow the utility to build and operate the new plant, even though it cannot do so as cheaply as the QF. This problem only arises where a new facility is involved. We have no idea how often the costs would be such that the more costly plant would be built,[12] but since the utility's customers would benefit whenever a QF builds a lower-cost plant than the utility can build, we tentatively recommend that this simultaneous buying and selling be permitted in connection with new facilities.[13]

With regard to existing facilities, however, the situation is exactly the reverse. Here, permitting a customer who has been providing part or all of its own power needs to sell to a utility at or near the utility's incremental cost and simultaneously buy back the same power at average embedded cost would drive up the costs of power to the utility's other customers without doing anything to encourage new cogeneration or desirable kinds of small power production. Thus we would recommend that the rule prohibit this practice.

As indicated in the preceding section, the ratemaking aspects of the interconnection costs may be handled in a variety of ways. Depending upon the size and type of generating equipment a QF has, whether or not the QF wants to operate in parallel with the interconnected utility, and the extent to which the QF expects to sell to the utility, many different types of facilities and arrangements may be appropriate. In many situations, all the required facilities may not be placed on the QF's facilities or at the point of interconnection; rather, it may be necessary for the utility to install or modify equipment elsewhere on the system in order to protect its and QF's equipment and operations.

While we are of the view that the authority to order interconnections is inherent in the Commission's other powers under Section 210, we do not regard this as settling the question of who bears the attendant cost. As to this question, we think the proscription against compelling to the utility's customers to subsidize QFs is dispositive: the QF should pay the reasonable costs of the interconnection necessary and appropriate to its circumstances. By the same token, however, the comparable costs attending the purchase or supplying of the same electric energy from an alternative source should be taken into account in determining the price the utility should pay the QF for electricity.

The recovery of the utility's costs of interconnection can be accomplished in either of two ways: through a lump-sum hook-up charge, or through a credit (where the utility is buying from the QF) or surcharge (where the QF is buying from the utility) to the basic price. Where these facilities' costs are to be amortized over a period of years or volume of sales, it would seem reasonable to allow the utility to secure its investment in some manner where either the financial integrity of the QF or the duration of the arrangement are in question.

As this entire discussion of pricing and interconnection indicates, the variety of arrangements that might be made between QFs and utilities is enormous. Therefore, we would recommend that the Commission promulgate broad general rules in the nature of guidelines, leaving flexibility for the States to experiment and accommodate local circumstances, and leaving room for the parties to negotiate the particular terms and conditions of their arrangements within the broad parameters of the Commission's rules. Under this approach, the States and the Commission would function more as arbitrators of disputes the parties can not resolve than as traditional regulators. This approach is, in our view, practically unavoidable with regard to the sales by QFs to utilities. On the other hand, as noted above, the sale from utilities to QFs is in most instances the type of transaction the States now regulate, and continuation of this regulation without substantial change is certainly a real option.

Finally, we must observe that the arbitration of disputes approach espoused above is not appropriate where a utility is participating in the ownership or even the operation of a QF. We would recommend that the specific terms of such arrangements be scrutinized by the States to ensure that the pricing or other provisions are not unduly discriminatory or beneficial.

Environmental Impact Statement

It appears to us that an environmental impact statement will not be necessary for Section 210 alone. We reach this preliminary conclusion on the basis that most of the effect of Section 210 flows from statutory mandates as to which the Commission has little or no discretion, the requirement that utilities buy from and sell to QFs; the requirement that the Commission grant exemptions necessary to encourage QFs (though it is not authorized to grant exemptions from environmental laws or regulations); and the requirement that prices be set within certain guidelines. In other words, we do not think that the Commission's adoption of one set of rules rather than another on those matters as to which the Commission has discretion or flexibility would constitute a major Federal action significantly affecting the quality of the human environment.

There does exist some question in our minds, though, as to whether the Section 201 rules together with the Section 210 rules might not require an environmental impact statement. The Section 201 rules will establish the fuel use and fuel efficiency standards for qualifying cogenerators and qualifying small power producers; and the Section 210 rules will describe with some greater specificity than does the statute the benefits of qualification. The environmental impact of this part of PURPA (whether or not the impact is significant) will be a product of the two rules acting together.

As stated elsewhere in this memorandum, we anticipate that the number, size, and kind of QFs that will develop will vary considerably from state to state and region to region. Similarly, the amount and kinds of utility fuel displaced by QFs will differ significantly around the country. As a consequence, the states would appear to be in a very good position to provide the information from which the Commission can determine whether the Section 201 and 210 rules would have a significant effect on the quality of the human environment, and whether that effect will be beneficial or detrimental. Therefore, we recommend that the Commission promptly invite comment from the States in particular and the public in general on this matter so that, at the least, there will be a basis for an assessment of environmental impact.

End of Memorandum.

Written Comments

Interested persons are invited to submit written comments on this staff paper to the Office of the Secretary, Federal Energy Regulatory Commission,

[12] Unfortunately, it is quite possible that the difference in the investment tax credits which may be available to, respectively, a utility and an owner of a QF will distort this cost comparison.

[13] Under the provisions of the Fuel Use Act of 1978, the sale of more than 50% of the output of a new installation would give the facility the status of an electric power plant. As a consequence, absent exemption on other grounds, a cogenerator could not use oil or gas as the basic generation fuel. However, the Fuel Use Act does not apply to installations consuming less than 100 million Btus per hour.

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825 North Capitol Street, N.E. Washington, D.C. 20426 Comments should reference Docket No. RM79-55 on the outside of the envelope and on all documents submitted to the Commission.

Fifteen (15) copies should be submitted. All comments and related information received by the Commission by August 1, 1979, will be considered prior to the promulgation of final regulations.

By the Commission.

Kenneth F. Plumb,

Secretary

[FR Doc. 79-20413 Filed 7-2-79; 8:45 am]

BILLING CODE 6450-01-M

Monday, February 25, 1980

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Docket No. RM79-55, Order No. 69]

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules require electric utilities to purchase electric power from and sell electric power to qualifying cogeneration and small power production facilities and provide for the exemption of qualifying facilities from certain Federal and State regulation. Implementation of these rules is reserved to State regulatory authorities and nonregulated electric utilities.

EFFECTIVE DATE: March 20, 1980.

FOR FURTHER INFORMATION CONTACT:
Ross Ain, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8466.
John O'Sullivan, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8477.
Adam Wenner, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8033.

Bernard Chew, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-376-9264.

SUPPLEMENTARY INFORMATION:

Issued February 19, 1980.

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) requires the Federal Energy Regulatory Commission (Commission) to prescribe rules as the Commission determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from and sell electric power to cogeneration and small power production facilities. Additionally, section 210 of PURPA authorizes the Commission to exempt qualifying facilities from certain Federal and State law and regulation.

Under section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities, and thus become eligible for the rates and exemptions set forth under section 210 of PURPA.

Cogeneration facilities simultaneously produce two forms of useful energy, such as electric power and steam. Cogeneration facilities use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. Thus, by using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's effort to conserve its energy resources.

Small power production facilities use biomass, waste, or renewable resources, including wind, solar and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume traditional fossil fuels to generate electric power.

Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally required to purchase the electric output, at an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to State and Federal regulation as an electric utility.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers. Section 210 also requires electric utilities to provide electric service to qualifying facilities at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act.

I. Procedural History

On June 28, 1979, in Docket No. RM79-54,[1] the Commission issued proposed rules to determine which cogeneration and small power production facilities may become "qualifying" cogeneration or small power production facilities under section 201 PURPA. Such qualifying facilities are entitled to avail themselves of the rate and exemption provisions under section 210 of PURPA; and qualifying cogeneration facilities are eligible for exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978.[2] The Commission will soon issue a final rule in Docket No. RM79-54.

As part of the rulemaking process in this docket, the Commission issued a Staff Discussion Paper[3] on June 27, 1979, addressing issues arising under section 210 of PURPA.

Public hearings on RM79-54 and the Staff Discussion Paper (RM79-55) were held in San Francisco on July 23, 1979, Chicago on July 27, 1979, and Washington, D.C. on July 30, 1979. Written comments were also received.

On October 18, 1979, the Commission issued a Notice of Proposed Rulemaking under Section 210 of PURPA in Docket No. RM79-55.[4] On October 19, 1979, the Commission made available its preliminary Environmental Assessment (EA) of the proposed rules in Docket Nos. RM79-54 and RM79-55. In a Request for Further Comments,[5] the Commission requested further public comment on both proposed rules, and on the findings set forth in the preliminary EA. In order to obtain the data, views, and arguments of interested parties, the Commission Staff held public hearings in Seattle on November 19, 1979, in New York on November 28, 1979, in Denver on November 30, 1979, and in Washington, D.C. on December 4 and 5, 1979. The Commission also received written comment.

After consideration of the comments, the Commission Staff made available a final draft rule on January 29, 1980. State public utility commissioners were invited to comment on the draft at a public meeting held on February 5, 1980. Representatives of electric utilities were invited to comment at a public meeting held on February 8, 1980. The Commission Staff also made itself available to any other interested parties who wished to comment. All of the comments were considered in the formulation of this final rule.

In the Staff Discussion Paper and the Request for Further Comments, it was stated that any environmental effects attributable to this program would result from the combined effect of these two rulemaking proceedings. As noted previously, the Commission intends to issue final rules in Docket No. RM79-54 in the near future. At that time, the Commission will also make available its final Environmental Assessment.

II. Summary

These rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems.

These rules also provide that electric utilities must furnish electric energy to qualifying facilities on a nondiscriminatory basis, and at a rate that is just and reasonable and in the public interest; and that they must provide certain types of service which may be requested by qualifying facilities to supplement or back up those facilities' own generation.

[1] [illegible]

[2] 44 FR 65744, November 15, 1979.

[3] 44 FR 38863, July 3, 1979.

[4] 44 FR 61190, October 24, 1979.

[5] 44 FR 61077, October 23, 1979.

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The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from certain provisions of the Federal Power Act, from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities. Within one year of the issuance of the Commission's rules, each State regulatory authority or nonregulated utility must implement these rules. That implementation may be accomplished by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the Commission's rules.

II. Section-by-Section Analysis

Subpart A—General Provisions

§ 292.101 *Definitions.*

This section contains definitions applicable to this part of the Commission's rules. Paragraph (a) provides that terms defined in PURPA have the same meaning as they have in PURPA, unless further defined in this part of the Commission's regulations. The definitions in PURPA are found in section 3 of that Act.

Subparagraph (1) defines a qualifying facility as a cogeneration or small power production facility which is a qualifying facility under Subpart B of the Commission's regulations. Those regulations implement section 201 of PURPA, and are the subject of Docket No. RM79-54.

Subparagraph (2) defines "purchase" as the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

Subparagraph (3) defines "sale" as the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

In the proposed rule, subparagraph (4) defined "system emergency" as a condition on a utility's system "which is likely to result in disruption of service to a significant number of customers or is likely to endanger life or property." In response to comments noting the difficulty in determining what constitutes a "significant number" of customers, the Commission has amended the definition to "a condition on an electric utility's system which is likely to result in imminent significant disruption of service to customers, or is imminently likely to endanger life or property." The emphasis is placed on the significance of the disruption of service, rather than on the number of customers affected.

Subparagraph (5) defines "rate" as any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

In the proposed rule, subparagraph (6) defined "avoided costs" as the costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source. This definition is derived from the concept of "the incremental cost to the electric utility of alternative electric energy" set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.

If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy costs.

The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used.

Many comments noted that the definition of "avoided cost" in the proposed rule failed to link the capacity costs which a utility might avoid as a result of purchasing electric energy or capacity or both from a qualifying facility with the energy costs associated with the new capacity. If the Commission required electric utilities to base their rates for purchases from a qualifying facility on the high capital or capacity cost of a base load unit and, in addition, provided that the rate for the avoided energy should be based on the high energy cost associated with a peaking unit, the electric utilities' purchased power expenses would exceed the incremental cost of alternative electric energy, contrary to the limitation set forth in the last sentence of section 210(b).

One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan,[6] *excluding* the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan *including* the qualifying facility.[7]

Subparagraph (7) defines "interconnection costs" as the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and

[6] An optimal capacity expansion plan is the schedule for the addition of new generating and transmission facilities which, based on an examination of capital, fuel, operating and maintenance costs, will meet a utility's projected load requirements at the lowest total cost.

[7] Throughout the rule and preamble, the phrase "energy or capacity" is used. This phrase is intended to include the capacity and energy costs associated with the capacity, if the purchase involves both energy or capacity.

The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from certain provisions of the Federal Power Act, from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities. Within one year of the issuance of the Commission's rules, each State regulatory authority or nonregulated utility must implement these rules. That implementation may be accomplished by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the Commission's rules.

III. Section-by-Section Analysis

Subpart A—General Provisions

§ 292.101 Definitions.

This section contains definitions applicable to this part of the Commission's rules. Paragraph (a) provides that terms defined in PURPA have the same meaning as they have in PURPA, unless further defined in this part of the Commission's regulations. The definitions in PURPA are found in section 3 of that Act.

Subparagraph (1) defines a qualifying facility as a cogeneration or small power production facility which is a qualifying facility under Subpart B of the Commission's regulations. Those regulations implement section 201 of PURPA, and are the subject of Docket No. RM79-54.

Subparagraph (2) defines "purchase" as the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

Subparagraph (3) defines "sale" as the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

In the proposed rule, subparagraph (4) defined "system emergency" as a condition on a utility's system "which is likely to result in disruption of service to a significant number of customers or is likely to endanger life or property." In response to comments noting the difficulty in determining what constitutes a "significant number" of customers, the Commission has amended the definition to "a condition on an electric utility's system which is likely to result in imminent significant disruption of service to customers, or is imminently likely to endanger life or property." The emphasis is placed on the imminence of the disruption of service, rather than on the number of customers affected.

Subparagraph (5) defines "rate" as any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

In the proposed rule, subparagraph (6) defined "avoided costs" as the costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source. This definition is derived from the concept of "the incremental cost to the electric utility of alternative electric energy" set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.

If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy costs.

The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used.

Many comments noted that the definition of "avoided cost" in the proposed rule failed to link the capacity costs which a utility might avoid as a result of purchasing electric energy or capacity or both from a qualifying facility with the energy costs associated with the new capacity. If the Commission required electric utilities to base their rates for purchases from a qualifying facility on the high capital or capacity cost of a base load unit and, in addition, provided that the rate for the avoided energy should be based on the high energy cost associated with a peaking unit, the electric utilities' purchased power expenses would exceed the incremental cost of alternative electric energy, contrary to the limitation set forth in the last sentence of section 210(b).

One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan,[4] *excluding* the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan *including* the qualifying facility.[5]

Subparagraph (7) defines "interconnection costs" as the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and

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[4] An optimal capacity expansion plan is the schedule for the addition of new generating and transmission facilities which, based on an examination of capital, fuel, operating and maintenance costs, will meet a utility's projected load requirements at the lowest t[illegible] cost.

[5] Throughout the rule and preamble, the phrase "energy or capacity" is used. This phrase is intended to include the capacity and energy costs associated with the capacity, if the purchase involves both energy or capacity.

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administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

The Commission has clarified this definition to include distribution and administrative costs associated with the interconnected operation, in response to comments indicating that the proposed rule was vague in these respects. This definition is designed to provide the State regulatory authorities and nonregulated electric utilities with the flexibility to ensure that all costs which are shown to be reasonably incurred by the electric utility as a result of interconnection with the qualifying facility will be considered as part of the obligation of the qualifying facility under § 292.306. These costs may include, but are not limited to, operating and maintenance expenses, the costs of installation of equipment elsewhere on the utility's system necessitated by the interconnection, and reasonable insurance expenses. However, the Commission does not expect that litigation expenses incurred by the utility involving this section will be considered a legitimate interconnection cost to be borne by the qualifying facility.

Certain interconnection costs may be incurred as a result of sales from a utility to a qualifying facility. The Commission notes that the Joint Explanatory Statement of the Committee of Conference (Conference Report) prohibits the use of "unreasonable rate structure impediments, such as unreasonable hook up charges or other discriminatory practices . . ." [3] This prohibition is reflected in § 292.306(a) of these rules, which provides that interconnection costs must be assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics.

A qualifying facility which is already interconnected with an electric utility for purposes of sales may seek to establish interconnection for the purpose of utility purchases from the qualifying facility. In this case, the qualifying facility may have compensated the utility for its interconnection costs with respect to sales to the qualifying facility, either as part of the utility's demand or energy charges, or through a separate customer charge. If this is the case, the interconnection costs associated with the purchase include only those additional interconnection expenses incurred by the electric utility as a result of the purchase, and do not include any portion of the interconnection costs for which the qualifying facility has already paid through its retail rates.

One comment recommended that the definition be revised to cover "all identifiable costs, including but not limited to, the costs of interconnection . . . resulting from interconnected operation". The Commission rejects this suggestion in order to maintain consistency with its initial determination to separate the utility's avoided costs with regard to purchases from qualifying facilities, from the costs incurred as a result of interconnection with a qualifying facility. Accordingly, legitimate costs not recovered pursuant to this section can be netted out in the calculation of avoided costs.

This definition also incorporates the concept from the proposed rule, as clarified in an erratum notice,[9] that these costs are limited to the net increased interconnection costs imposed on an electric utility compared to those interconnection costs it would have incurred had it generated the energy itself or purchased an equivalent amount of energy or capacity from another source.

This section of the rule contains definitions of "supplementary power", "back-up power", "interruptible power", and "maintenance power" which did not appear in the proposed rule.

Subparagraph (8) defines "supplementary power" as electric energy or capacity, supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

Subparagraph (9) defines "back-up power" as electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

Subparagraph (10) defines "interruptible power" as electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

Subparagraph (11) defines "maintenance power" as electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§ *292.301 Scope.*

Section 292.301(a) describes the scope of Subpart C of Part 292 of the Commission's rules. Subpart C applies to sales and purchases of electric energy or capacity between qualifying cogeneration or small power production facilities and electric utilities, and actions related to such sales and purchases. Section 292.301(b)(1) provides that this subpart does not preclude negotiated agreements between qualifying cogenerators or small power producers and electric utilities which differ from rates, or terms or conditions which would otherwise be required under the subpart. Paragraph (b)(2) states that this subpart does not affect the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.[10]

Paragraph (b)(1) reflects the Commission's view that the rate provisions of section 210 of PURPA apply only if a qualifying cogenerator or small power production facility chooses to avail itself of that section. Agreements between an electric utility and a qualifying cogenerator or small power producer for purchases at rates different than rates required by these rules, or under terms or conditions different from those set forth in these rules, do not violate the Commission's rules under section 210 of PURPA. The Commission recognizes that the ability of a qualifying cogenerator or small power producer to negotiate with an electric utility is buttressed by the existence of the rights and protections of these rules.

Some comments stated that paragraph (b)(2) would unfairly penalize cogenerators and small power producers who, prior to the promulgation of these regulations, entered into binding contracts with electric utilities under less favorable terms than might be obtainable under these rules. The Commission interprets its mandate under section 210(a) to prescribe "such rules as it determines necessary to encourage cogeneration and small

[3] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

[9] 44 FR 63114, November 2, 1979

[10] The term "purchase" is defined in § 292.101(b)

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power production * * *" to mean that the total costs to the utility and the rates to its other customers should not be greater than they would have been had the utility not made the purchase from the qualifying facility or qualifying facilities. That a cogeneration or small power production facility entered into a binding contractual arrangement with an electric utility indicates that it is likely that sufficient incentive existed, and that the further encouragement provided by these rules was not necessary. As a result, the Commission has not revised this provision.

§ 292.302 *Availability of electric utility system cost data.*

As the Commission observed in the Notice of Proposed Rulemaking, in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility. This return will be determined in part by the price at which the qualifying facility can sell its electric output. Under § 292.304 of these rules, the rate at which a utility must purchase that output is based on the utility's avoided costs, taking into account the factors set forth in paragraph (e) of that section. Section 292.302 of these rules is intended by the Commission to assist those needing data from which avoided costs can be derived. It requires electric utilities to make available to cogenerators and small power producers data concerning the present and anticipated future costs of energy and capacity on the utility's system.

In the preamble to the proposed rule, the Commission stated that most electric utilities will have prepared data containing some of this information in compliance with the Commission's rules implementing section 133 of PURPA. Several commenters observed that the marginal cost data required to be provided pursuant to section 133 cannot be directly translated into a rate for purchases. The Commission has clarified paragraph (b) to emphasize that these data are not intended to represent a rate for purchases from qualifying facilities. Rather, these data are to be considered the first step in the determination of such a rate.

The Commission has also revised this section so that the rates for purchases can be more readily calculated from the data produced. The Commission has changed paragraph (b)(3) to provide that a utility shall submit the associated energy cost of each planned unit expressed in kilowatt-hours (kWh) along with the estimated capacity cost of planned capacity additions. This change is intended to ensure that the calculation of avoided costs includes the lower energy costs that might be associated with the new capacity. The Commission points out that the determination of a rate for purchases from a qualifying facility which enables a utility to defer or avoid the addition of a new unit must also reflect the hours of expected use of the deferred or avoided capacity addition.

The coverage under paragraph (a) of this section is the same as that provided pursuant to section 133 of PURPA and the Commission's rules implementing that section.[11] As noted in the Notice of Proposed Rulemaking, section 133 of PURPA applies to each electric utility whose total sales of electric energy for purposes other than resale exceeded 500 million kWh during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

Paragraph (b) provides that each regulated electric utility meeting the requirements of paragraph (a) must furnish to its State regulatory authority, and maintain for public inspection, data related to the costs of energy and capacity on the electric utility's system. Each nonregulated electric utility also must maintain such data for public inspection.

In response to comments received, the Commission has extended the date by which these data must be first provided to November 1, 1980, and changed the second date to May 31, 1982, to conform to the dates required by the Commission's regulations implementing section 133 of PURPA. The Commission has added paragraph (d) to allow a State regulatory authority or nonregulated utility to use a different approach than that provided in paragraph (b). As part of that substitute program, a State regulatory authority or nonregulated electric utility could provide that cost data be updated more frequently than every two years.

Subparagraph (1) of paragraph (b) requires each electric utility to provide the estimated avoided cost of energy on its system for various levels of purchases from qualifying facilities. The levels of purchases are to be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than ten percent of system peak demand for systems less than 1000 megawatts. This information is to be stated on a cents per kilowatt-hour basis, for daily and seasonal peak and off-peak periods, for the current calendar year and for each of the next five years.

Subparagraph (2) of paragraph (b) requires each electric utility to provide its schedule for the addition of capacity, planned purchases of firm energy and capacity, and planned capacity retirements for each of the next ten years.

Subparagraph (3) of paragraph (b) has been revised, as discussed previously, so that the costs of planned capacity additions include the associated energy costs.

The Commission received comment noting that some States have implemented or are planning to implement alternative methods by which electric utilities' system cost data would be made available. In order to prevent the preparation of duplicative data where the alternative method substantially deviates from the Commission approach, the Commission has added paragraph (d). This paragraph provides that any State regulatory authority or nonregulated electric utility may, after providing public notice in the area served by the utility and after opportunity for public comment, require data different than that which are otherwise required by this section if it determines that avoided costs can be derived from such data. Any State regulatory authority or nonregulated utility shall notify the Commission within 30 days of any determination to sustitute data requirements.

If a qualifying facility finds that the alternative requirements do not provide sufficient data from which avoided costs may be derived, the qualifying facility may seek court review of the matter as it can with regard to any other aspect of the State's implementation of this program.

A qualifying facility may wish to sell energy or capacity to an electric utility which is not subject to the reporting requirements of paragraph (b). In that event, paragraph (c) provides that, upon request of a qualifying facility, an electric utility not otherwise covered by paragraph (b) must provide data sufficient to enable the cogenerator or small power producer to estimate the utility's avoided costs. If such utility does not supply the requested data, the qualifying facility may apply to the State regulatory authority which has ratemaking authority over the utility or to this Commission for an order requiring that the information be supplied. The consideration of such applications should take into account the burden imposed on the small utilities.

[11] 44 FR 58687, October 11, 1979.

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An electric utility which is legally obligated to obtain all of its requirements for electric energy and capacity from another utility may provide the data provided by its supplying utility and the rates at which it currently purchases such energy and capacity for any period during which this obligation will continue. The wholesale rates may require adjustment in order to reflect properly the avoided costs. This is discussed later in this preamble under § 292.303. In the case of small, non-generating utilities, the requirements of this section will be considered to have been satisfied if these cost data are readily available from the supplying utility.

Numerous comments mentioned that the proposed rule did not address the issue of validation of the data to be provided pursuant to this section. As a result, the Commission has added paragraph (e) which provides that any data submitted by an electric utility under this section shall be subject to review by its State regulatory authority. Paragraph (e)(2) places the burden of providing support for the data on the utility supplying the data.

§ 292.303 Electric utility obligations under this subpart.

Section 210(a) of PURPA provides that the Commission prescribe rules requiring electric utilities to offer to purchase electric energy from qualifying facilities. The Commission interprets this provision to impose on electric utilities an obligation to purchase all electric energy and capacity made available from qualifying facilities with which the electric utility is directly or indirectly interconnected, except during periods described in § 292.304(f) or during system emergencies.

A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.

§ 292.303(a) Obligation to purchase from qualifying facilities.

§ 292.303(d) Transmission to other electric utilities. All-Requirement Contracts.

Several commenters noted that the obligation to purchase from qualifying facilities under this section might conflict with contractual commitments into which they had entered requiring them to purchase all of their requirements from a wholesale supplier. One commenter noted that, with regard to all-requirements rural electric cooperatives, any impairment of the obligation to obtain all of a cooperative's requirements from a generation and transmission cooperative might affect the financing ability of the generation and transmission cooperative. The Commission observes that, in general, if it permitted such contractual provisions to override the obligation to purchase from qualifying facilities, these contractual devices might be used to hinder the development of cogeneration and small power production. The Commission believes that the mandate of PURPA to encourage cogeneration and small power production requires that obligations to purchase under this provision supersede contractual restrictions on a utility's ability to obtain energy or capacity from a qualifying facility.

The Commission has, however, provided an alternate means by which any electric utility can meet this obligation. Under paragraph (d), if the qualifying facility consents, an all-requirements utility which would otherwise be obligated to purchase energy or capacity from the qualifying facility would be permitted to transmit the energy or capacity to its supplying utility. In most instances, this transaction would actually take the form of the displacement of energy or capacity that would have been provided under the all-requirements obligation. In this case, the supplying utility is deemed to have made the purchase and, as a result the all-requirements obligation is not affected.

In addition, if compliance with the purchase obligation would impose a special hardship on an all-requirements customer, the Commission may consider waiving such purchase obligation pursuant to the procedures set forth in § 292.403.

Transmission to Other Facilities

There are several circumstances in which a qualifying facility might desire that the electric utility with which it is interconnected not be the purchaser of the qualifying facility's energy and capacity, but would prefer instead that an electric utility with which the purchasing utility is interconnected make such a purchase. If, for example, the purchasing utility is a non-generating utility, its avoided costs will be the price of bulk purchased power ordinarily based on the average embedded cost of capacity and average energy cost on its supplying utility's system. As a result, the rate to the qualifying facility would be based on those average costs. If, however, the qualifying facility's output were purchased by the supplying utility, its output ordinarily will replace the highest cost energy on the supplying utility's system at that time, and its capacity might enable the supplying utility to avoid the addition of new capacity. Thus, the avoided costs of the supplying utility may be higher than the avoided cost of the non-generating utility.

This would not appear to be the case if the qualifying facility offers to supply capacity and energy in a situation in which the supplying utility is in an excess capacity situation. Since the supplying utility has excess capacity, its avoided costs would include only energy costs. On the other hand, if the avoided cost were based on the wholesale rate to the all-requirements utility, the avoided cost would include the demand charge included in the wholesale rate, which would usually reflect an allocation of a portion of the fixed charges associated with excess capacity.

Use of the unadjusted wholesale rate fails to take into account the effect of reduced revenue to the supplying utility, as a result of the substitute of the qualifying facility's output for energy previously supplied by the supplying utility. As the level of purchase by the all-requirements utility decreases, the supplying utility's fixed costs will have to be allocated over a smaller number of units of output. In effect, the loss in revenue to the supplying utility will cause the demand charges to the supplying utility's customers (including the all-requirements customers interconnected with the qualifying facility) to increase. Under the definition of "avoided costs" in this section, the purchasing utility must be in the same financial position it would have been had it not purchased the qualifying facility's output. As a result, rather than allocating its loss in revenue among all of its customers, in this situation the supplying utility should assign all of these losses to the all-requirements utility. That utility should, in turn, deduct these losses from its previously calculated avoided costs, and pay the qualifying facility accordingly.

Under these rules, certain small electric utilities are not required to provide system cost data, except upon request of a qualifying facility. If, with the consent of the qualifying facility, a small electric utility chooses to transmit energy from the qualifying facility to a second electric utility, the small utility

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can avoid the otherwise applicable requirements that it provide the system cost data for the qualifying facility and that it purchase the energy itself. However, the ability to transmit a purchase to another utility is not limited to these smaller systems; it applies to any utility.

Accordingly, paragraph (d) provides that a utility which receives energy or capacity from a qualifying facility may, with the consent of the qualifying facility, transmit such energy to another electric utility. However, if the first facility does not agree to transmit the purchased energy or capacity, it retains the purchase obligation. In addition, if the qualifying facility does not consent to transmission to another utility, the first utility retains the purchase obligation. Any electric utility to which such energy or capacity is delivered must purchase this energy under the obligations set forth in these rules as if the purchase were made directly from the qualifying facility.

One commenter stated that this provision could result in energy being transmitted to a utility which has little or no information regarding the reliability of the qualifying facility. The Commission believes that, prior to these transactions occurring, it will be in the interest of the qualifying facility to inform any utility to which energy or capacity is delivered, of the nature of these deliveries, so that such energy or capacity can be usefully integrated into that utility's power supply.

Several other commenters believed that this provision went beyond the authority of section 210 of PURPA—namely, that the Commission cannot require the first utility to wheel the power nor the second utility to buy the power. First, the Commission notes that the transmission can only occur with the consent of the utility to which energy or capacity from the qualifying facility is made available. Thus, no utility is forced to wheel. Secondly, section 210 does not limit the obligation to purchase to any particular utility; rather, it is a generally applicable [illegible].

Paragraph (d) provides that charges for transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. In the case of utilities not subject to the jurisdiction of this Commission, these charges should be determined under applicable State law or regulation which [illegible] agreement between the qualifying facility and any electric utility which transmits energy or capacity with the consent of the qualifying facility. For utilities subject to the Commission's jurisdiction under Part II of the Federal Power Act, these charges will be determined pursuant to Part II.

The electric utility to which the electric energy is transmitted has the obligation to purchase the energy at a rate which reflects the costs that it can avoid as a result of making such a purchase. In cases in which electricity actually travels across the transmitting utility's system, the amount of energy delivered will be less than that transmitted, due to line losses. When this occurs, the rate for purchase can reflect these losses. In other cases, the energy supplied by the qualifying facility will displace energy that would have been supplied by the purchasing utility to the transmitting utility. In those cases, a unit of energy supplied from the qualifying facility may replace a greater amount of energy from the purchasing utility. In that case, the rate for purchase should be increased to reflect the net gain. These provisions are also set forth in paragraph (d).

§ 292.303(b) *Obligation to sell to qualifying facilities.*

Paragraph (b) sets forth the statutory requirement of section 210(a) of PURPA that each electric utility offer to sell electric energy to qualifying facilities. The Commission observed in the Notice of Proposed Rulemaking that State law ordinarily sets out the obligation of an electric utility to provide service to customers located within its service area. In most instances, therefore, this rule will not impose additional obligations on electric utilities.

It is possible that a qualifying facility located outside the service area of an electric utility might require back-up, maintenance, or other types of power. The Commission believes that the instructions of section 210(a) of PURPA that it issue rules "as it determines necessary to encourage cogeneration and small power production * * *" mandate that it assure that such facilities are able to fulfill their needs for service.

However, the Commission also recognizes that State and local law limits the authority of some electric utilities to construct lines outside of their service area. Accordingly, the Commission requires electric utilities to serve any qualifying facility, and, subject to the restriction contained therein, to interconnect with any such facility as required in paragraph (c). However, an electric utility is only required to construct lines or other facilities to the extent authorized or required by State or local law. As a result, a qualifying facility outside the service area of a utility may be required to build its line into the service area of the utility.

§ 292.303(c) *Obligation to interconnect*

In the Notice of Proposed Rulemaking the Commission used the interpretation set forth in the Staff Discussion Paper, that the obligation to interconnect with a qualifying facility is subsumed within the requirement of section 210(a) that electric utilities offer to sell electric energy to and purchase electric energy from qualifying facilities. The Commission observed that to hold otherwise would mean that Congress intended to require that qualifying facilities go through the complex procedures simply to gain interconnection, contrary to the mandate of section 210 of PURPA to encourage cogeneration and small power production.

During the comment period, this question was further explored, and it was suggested that the Commission has ample authority under the general mandate of section 210(a) of PURPA—namely, that it prescribe rules necessary to encourage cogeneration and small power production—to require interconnection.

While these interpretations received substantial support in the comments submitted, they were at the same time criticized on the theory that section 210(e)(3) of PURPA does not provide that a qualifying facility may be exempted from section 210 of the Federal Power Act (added by section 202 of PURPA and providing certain interconnection authority) and that this interconnection section specifically includes qualifying cogenerators and small power producers in its applicability. These commenters contended that since section 210 of the Federal Power Act deals explicitly with the subject of interconnections between qualifying facilities and electric utilities, no other section of that Act can be interpreted as also granting authority on that subject, as such an interpretation would render the express provision "surplusage".

With regard to these criticisms, the Commission observes that this argument might be tenable in the situation in which the section of the legislation which deals explicitly with the subject does not contain an express provision that it is not to be considered the exclusive authority on the subject. The Commission notes that section 212 of the Federal Power Act (as added by section 204 of PURPA) sets forth certain determinations that the Commission must make before it can issue an order under either section 210 or 211 of the Federal Power Act.

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Section 212(e) states that no provision of section 210 of the Federal Power Act shall be treated "(1) as requiring any person to utilize the authority of such section 210 or 211 in lieu of any other authority of law, or (2) as limiting, impairing, or otherwise affecting any other authority of the Commission under any other provision of law." Thus, the Federal Power Act, as amended, expressly provides that the existence of authority under section 210 of the Federal Power Act to require interconnection is not to be interpreted as excluding any other interconnection authority available under any other law. The Commission emphasizes that the limitation is not restricted to the Federal Power Act, but rather extends to include other authority of law, such as the authority contained in the Public Utility Regulatory Policies Act of 1978, of which section 210 is a part. Clearly, the existence of this provision refutes the contention that section 210 of the Federal Power Act represents the exclusive method by which interconnection can be obtained. As a result, the comment that the direction contained in section 210(e)(3) of PURPA that no qualifying facility can be exempted from section 210 or 212 of the Federal Power Act is not persuasive.

The Commission finds that to require qualifying facilities to go through the complex procedures set forth in section 210 of the Federal Power Act to gain interconnection would, in most circumstances, significantly frustrate the achievement of the benefits of this program. The Commission does not feel that the legal interpretation set forth in the Staff Discussion Paper and the Notice of Proposed Rulemaking is the exclusive theory by which it may require interconnections under this program without resort to sections 210 and 212 of the Federal Power Act. The interpretation brought out during the comment period—that section 210(a) of PURPA provides a general mandate for the Commission to prescribe rules necessary to encourage cogeneration and small power production—provides, in the Commission's view, sufficient authority to require interconnection. The Commission believes that a basic purpose of section 210 of PURPA is to provide a market for the electricity generated by small power producers and cogenerators. The Commission believes that accomplishment of this purpose would be greatly hindered if it were to require qualifying facilities to utilize section 210 of the Federal Power Act as the exclusive means of obtaining interconnection. It therefore concludes that such a restrictive interpretation of the law is not supportable.

Paragraph (c)(1) thus provides that an electric utility must make any interconnections with a qualifying facility which may be necessary to permit purchases from or sales to the qualifying facility. A State regulatory authority or nonregulated electric utility must enforce this requirement as part of its implementation of the Commission's rules.

In addition, several commenters contended that, if the obligation to interconnect is required under section 210(a) PURPA, the limitation provided in section 212 of the Federal Power Act would not be available. That limitation provides that an electric utility which complies with an interconnection order under section 210 of the Federal Power Act would not be subject to the jurisdiction of the Federal Energy Regulatory Commission for any purposes other than those specified in the interconnection order.

After consideration of this concern, the Commission has added paragraph (c)(2) to provide that no electric utility is required to interconnect with any qualifying facility, if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act. This exception is provided because the Commission notes that, in balance, the encouragement of cogeneration and small power production would not be furthered if, by virtue of interconnection with a qualifying facility, a previously nonjurisdictional utility were reluctantly to become subject to federal utility regulation.

§ 292.303(e) Parallel operation.

In the Notice of Proposed Rulemaking, the Commission provided that each electric utility must offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with standards established by the State regulatory authority or nonregulated electric utility with regard to the protection of system reliability pursuant to § 292.308. By operating in parallel, qualifying facilities are enabled to export automatically any electric energy which is not consumed by its own load. The comments submitted have not set forth any convincing reasons for changing the proposed rule. Paragraph (e) thus continues to require each electric utility to offer to operate in parallel with a qualifying facility.

§ 292.304 Rates for purchases.

Section 210(b) of PURPA provides that in requiring any electric utility to purchase electric energy from a qualifying facility, the Commission must ensure that the rates for the purchase be just and reasonable to the electric consumers of the purchasing utility, in the public interest, and nondiscriminatory to qualifying facilities, but that they not exceed the incremental costs of alternative electric energy (the costs of energy to the utility, which, but for the purchase, the utility would generate itself or purchase from another source).

Relation to State Programs

The Commission has become aware that several States have enacted legislation requiring electric utilities in that State to purchase the electrical output of facilities which may be qualifying facilities under the Commission's rules at rates which may differ from the rates required under the Commission's rules implementing section 210 of PURPA.

This Commission has set the rate for purchases at a level which it believes appropriate to encourage cogeneration and small power production, as required by section 210 of PURPA. While the rules prescribed under section 210 of PURPA are subject to the statutory parameters, the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies. However, State laws or regulations which would provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies, and must yield to federal law.

If a State program were to provide that electric utilities must purchase power from certain types of facilities, among which are included "qualifying facilities," at a rate higher than that provided by these rules, a qualifying facility might seek to obtain the benefits of that State program. In such a case, however, the higher rates would be based on State authority to establish such rates, and not on the Commission's rules.

A facility which provides energy or capacity to a utility under State authority may nevertheless seek to obtain exemption from the Federal Power Act, the Public Utility Holding Company Act, and State regulation of electric utilities as available under section 210(e) of PURPA. The Commission notes that the States lack the authority to exempt a facility from

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the Federal Power Act or Public Utility Holding Company Act. The Commission finds no inconsistency in a facility's taking advantage of section 210 in order to obtain one of its benefits, while relying on other authority under which to buy from or sell to a utility.

§ 292.304(a) Rates for purchases.

Paragraph (a) sets forth the statutory requirement that rates for purchases be just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against qualifying cogeneration and small power production facilities.

In the proposed rule, the Commission stated that there is a rebuttable presumption that the rate for purchases is acceptable if it reflects the avoided cost resulting from a purchase on the basis of system cost data set forth pursuant to § 292.302 (b) or (c). Many of the comments received stated that this section was ambiguous.[11] The Commission has therefore provided that the rate for purchases meets the statutory requirements if it equals avoided costs, and has eliminated the reference to the "rebuttable presumption".

Some comments recommended that, as a matter of policy, this section be revised to provide that a State regulatory authority or nonregulated utility has discretion to establish the relationship between the avoided cost and the rate for purchases. Other commenters contended that the Commission should specify that the rate for purchase must equal the avoided cost resulting from such a purchase. In addition, several suggested that the Commission adopt a "split-the-savings" approach.

It is possible that developers of technologies which may be included as qualifying facilities may produce and make available power to electric facilities even though their cost of producing this power is greater than the utility's avoided costs. In most instances, however, purchases of energy or capacity from qualifying facilities will only occur when the cost to the qualifying cogenerator or small power producer of producing the energy or capacity is lower than the utility's avoided costs. Only if this is the case, will payment by the utility of its avoided costs provide economic benefit for the cogenerator or small power producer.

When one electric utility can provide energy more cheaply than could another electric utility, the two utilities will often exchange power on a "split-the-savings" basis. In that type of transaction, the two utilities split the difference between the incremental costs incurred and the incremental costs that the purchasing utility would have incurred had it generated the power itself. Several commenters argued that rates for purchases from qualifying facilities should be based upon this same general principle. The effect of such a pricing mechanism would be to transfer to the utility's ratepayers a portion of the savings represented by the cost differential between the qualifying facility and the purchasing electric utility. Several utilities contend that by so allocating these savings, the Commission would provide an incentive for the electric utility to enter into purchase transactions with qualifying cogeneration and small power production facilities.

These commenters also noted that they had previously engaged in purchases from facilities which might become qualifying facilities under the Commission's rules, and they had paid prices for these purchases based on a "split-the-savings" methodology. These commenters observed that if the Commission's rules now require the payment of full avoided cost for these types of purchases, the purchased power expenses of the electric utility would increase.

Moreover, several utilities commented that, for the foreseeable future, they are inextricably tied to the use of oil to produce electricity. They contend that unless they are permitted to purchase energy and capacity from qualifying facilities at a rate somewhere between the qualifying facilities' costs and their own costs, they and their ratepayers will be subject to the continually increasing world price of oil.

Commenters opposing this allocation of savings to parties other than the qualifying facility noted that this section of PURPA is intended to encourage the development of cogeneration and small power production. They noted that in providing for this encouragement, the Commission may not set rates for purchases at a level which exceeds the incremental cost of alternative energy. Therefore, they observed that, under the full avoided cost standard, the utilities' customers are kept whole, and pay the same rates as they would have paid had the utility not purchased energy and capacity from the qualifying facility.

Although use of the full avoided cost standard will not produce any rate savings to the utility's customers, several commenters stated that these ratepayers and the nation as a whole will benefit from the decreased reliance of scarce fossil fuels, such as oil and gas, and the more efficient use of energy.

The Commission notes that, in most instances, if part of the savings from cogeneration and small power production were allocated among the utilities' ratepayers, any rate reductions will be insignificant for any individual customer. On the other hand, if these savings are allocated to the relatively small class of qualifying cogenerators and small power producers, they may provide a significant incentive for a higher growth rate of these technologies.

Another concern with the use of a split-the-savings rate for purchases is that it would require a determination of the costs of production of the qualifying facility. A major portion of this legislation is intended to exempt qualifying facilities from the cost-of-service regulation by which electric utilities traditionally have been regulated. The Conference Report noted that:

> It is not the intention of the Conferees that cogenerators and small power producers become subject . . . to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[12]

Thus, section 210(e) of PURPA provides that the Commission shall exempt qualifying facilities from the Public Utility Holding Company Act, from the Federal Power Act and from State law and regulation respecting utility rates or financial organization, to the extent that the Commission determines that such exemption is necessary to encourage cogeneration or small power production.

Several commenters have contended that a determination of the qualifying facility's costs can be made without the detail required by cost-of-service regulation. However, the Commission believes that the basis for the determination of rates for purchases should be the utility's avoided costs and should not vary on the basis of the costs of the particular qualifying facility.

Several commenters recommended that rather than using a split-the-savings approach, the Commission should set rates for purchases at a fixed percentage of avoided costs. The Commission notes that, in most situations, a qualifying cogenerator or small power producer will only produce energy if its marginal cost of production is less than the price he receives for its output. If some fixed percentage is used, a qualifying facility

[11] The relationship between the utility system cost [illegible] and the rate for purchases is discussed under [illegible] and § 292.304(b).

[12] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

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...y cease to produce additional units of ...ergy when its costs exceed the price ...be paid by the utility. If this occurs, the utility will be forced to operate ...erating units which either are less ...ficient than those which would have been used by the qualifying facility, or which consume fossil fuel rather than the alternative fuel which would have been consumed by the qualifying facility had the price been set at full avoided ...sts.

...2.304(b) Relationship to avoided ... Capacity"

The proposed rule differentiated ...een "old" and "new" production in ...ection with simultaneous purchases ...sales. The proposed rule required ...ectric utility to purchase at its ...d cost the total output of a ...y, construction of which was ...enced after the date of issuance of ...rules, even if the utility ...neously sells energy to the ...y at its retail rate. The effect of ...oposed rule was to separate the ...tion aspect of a qualifying facility ...s consumption function. Under ...proach, the electrical output of a ...is viewed independently of its ...al needs. Thus, if a cogeneration ...produces five megawatts, and ...es three megawatts, it is treated ...e as another qualifying facility ...duces five megawatts, and that ...ed next to a factory that uses ...egawatts.

...Commission continues to believe ...mitting simultaneous purchase ...it is necessary and appropriate to ...ge cogeneration and small ...production. The limitation ...ed in the proposed rule was ...d to prevent a cogenerator or ...wer producer, which had found ...mical to produce power for its ...sumption prior to the issuance ...rules, from receiving the ...rent that might result from the ...o of its entire output at a utility's ...ded cost after that date without ...stment on the part of the ...ing facility.

...me reasoning applies to any ...which was in existence prior to ...ment of PURPA, whether or not ...to purchase and sell ...eously. That construction of the ...as commenced prior to that ...indicate that appropriate ...returns were available ...further incentives provided ...210.

...mmission is aware that in ...ces, if a previously existing ...facility were not permitted to receive full avoided costs for its entire output, it would no longer have sufficient incentive to continue to produce electric power. The cost of production may have risen so as to render the previous rate insufficient to cover the costs of production, or permit an appropriate return.

Thus, with regard to facilities, construction of which commenced on or after the date of enactment of PURPA (November 9, 1978), the Commission has determined it appropriate to provide that rates for purchases shall equal full avoided costs. For facilities, construction of which commenced before the enactment of PURPA, the Commission will permit the State regulatory authorities and nonregulated electric utilities to establish rates for purchases at full avoided costs, or at a lower rate, if the State regulatory authority or nonregulated electric utility determines that the lower rate will provide sufficient encouragement of cogeneration and small power production. Thus, if a previously existing facility shows that it requires rates for purchases based on full avoided costs to remain viable, or to increase its output, the State regulatory authority or nonregulated electric utility is required to establish such rates. This distinction is intended to reflect the need for further incentives and the reasonable expectations of persons investing in cogeneration or small power production facilities prior to or subsequent to the enactment of this law.

Paragraph (b)(1) defines "new capacity" as any purchase of capacity from a qualifying facility, construction of which was commenced on or after November 9, 1978. Subparagraph (2) provides that for new capacity, utilities must pay a rate which equals their avoided cost.

A utility must therefore purchase all of the output from a qualifying facility. However, as explained above, for any portion of that output which is not "new capacity," the State regulatory authority or nonregulated electric utility, as provided in paragraph (b)(3), may provide for a lower rate, if it determines that the lower rate will provide sufficient incentive for cogeneration.

Paragraph (b)(4) requires electric utilities to pay full avoided costs for purchases from new capacity made available from a qualifying facility, regardless of whether the electric utility is simultaneously making sales to the qualifying facility.

§ 292.304(c) Standard rates for purchases.

The Notice of Proposed Rulemaking required electric utilities on request of a qualifying facility to establish a tariff or other method for establishing rates for purchase from qualifying facilities of 10 kw or less. Upon consideration of the comments received, the Commission has determined that the concept of requiring a standard rate for purchases should be retained. Several comments stated that this requirement could similarly be applied to facilities of up to 100 kw or less.

The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standardized tariffs be implemented for facilities of 100 kw or less.

In addition, some commenters pointed out that standard tariffs can be used on a technology specific basis, to reflect the supply characteristics of the particular technology. Some commenters also observed that the proposed rule did not require that standard rates for purchases from these small facilities be based on the purchasing utility's avoided cost. This omission might have permitted a utility to pay less than that rate for purchases.

The Commission has accordingly revised paragraph (c) to require each State regulatory authority or nonregulated electric utility to cause to be put into effect standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The revised rule requires that standard rates for purchases equal the purchasing utility's avoided cost pursuant to paragraphs (a), (b), and (e).

Several commenters noted that standard rates for purchases can also be usefully applied to larger facilities. The Commission believes that the establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates accurately reflect the costs that the utility can avoid as a result of such purchases. Accordingly, the Commission has added subparagraph (2) which permits, but does not require, State regulatory authorities and nonregulated electric utilities to put into effect a standard rate for purchases from qualifying facilities with a design capacity greater than 100 kilowatts. These rates must equal avoided cost pursuant to paragraphs (a), (b), and (e).

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Many commenters at the Commission's public hearings and in written comments recommended that the Commission should require the establishment of "net energy billing" for small qualifying facilities. Under this billing method, the output from a qualifying facility reverses the electric meter used to measure sales from the electric utility to the qualifying facility. The Commission believes that this billing method may be an appropriate way of approximating avoided cost in some circumstances, but does not believe that this is the only practical or appropriate method to establish rates for small qualifying facilities. The Commission observes that net energy billing is likely to be appropriate when the retail rates are marginal cost-based, time-of-day rates. Accordingly, the Commission will leave to the State regulatory authorities and the nonregulated electric utilities the determination as to whether to institute net energy billing.

Paragraph (c)(3)(i) provides that standard rates for purchase should take into account the factors set forth in paragraph (e). These factors relate to the quality of power from the qualifying facility, and its ability to fit into the purchasing utility's generating mix.

Paragraph (e)(vi) is of particular significance for facilities of 100 kW or less. This paragraph provides that rates for purchase shall take into account "the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system . . .". Several commenters presented persuasive evidence showing that an effective amount of capacity may be provided by dispersed small systems, even in the case where delivery of energy from any particular facility is stochastic. Similarly, qualifying facilities may be able to enter into operating agreements with each other by which they are able to increase the assured availability of capacity to the utility by coordinating scheduled maintenance and providing mutual back-up service. To the extent that this aggregate capacity value can be reasonably estimated, it must be reflected in standard rates for purchases.

Several commenters observed that the patterns of availability of particular energy sources can and should be reflected in standard rates. An example of this phenomenon is the availability of wind and photovoltaic energy on a summer peaking system. If it can be shown that system peak occurs when there is bright sun and no wind, rates for purchase could provide a higher capacity payment for photovoltaic cells than for wind energy conversion systems. For systems peaking on dark windy days, the reverse might be true. Subparagraph (3)(ii) thus provides that standard rates for purchases may differentiate among qualifying facilities on the basis of the supply characteristics of the particular technology.

§§ 292.304 (b)(5) and (d) Legally enforceable obligations.

Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers. The Commission recognizes this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase. The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities.

Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.

Paragraph (b)(5) addresses the situation in which a qualifying facility has entered into a contract with an electric utility, or where the qualifying facility has agreed to obligate itself to deliver at a future date energy and capacity to the electric utility. The import of this section is to ensure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances. This provision can also work to preserve the bargain entered into by the electric utility; should the actual avoided cost be higher than those contracted for, the electric utility is nevertheless entitled to retain the benefit of its contracted for, or otherwise legally enforceable, lower price for purchases from the qualifying facility. This subparagraph will thus ensure the certainty of rates for purchases from a qualifying facility which enters into a commitment to deliver energy or capacity to a utility.

Paragraph (d)(1) provides that a qualifying facility may provide energy or capacity on an "as available" basis, i.e., without legal obligation. The proposed rule provided that rates for such purchases should be based on "actual" avoided costs. Many comments noted that basing rates for purchases in such cases on the utility's "actual avoided costs" is misleading and could require retroactive ratemaking. In light of these comments, the Commission has revised the rule to provide that the rates for purchases are to be based on the purchasing utility's avoided costs estimated at the time of delivery.[14]

Paragraph (d)(2) permits a qualifying facility to enter into a contract or other legally enforceable obligation to provide energy or capacity over a specified term. Use of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility.

Many commenters noted the same problems for establishing rates for purchases under subparagraph (2) as in subparagraph (1). The Commission intends that rates for purchases be based, at the option of the qualifying facility, on either the avoided costs at the time of delivery or the avoided costs calculated at the time the obligation is incurred. This change enables a qualifying facility to establish a fixed contract price for its energy and capacity at the outset of its obligation or to receive the avoided costs determined at the time of delivery.

A facility which enters into a long term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or non-regulated electric utility from approving such an arrangement.

[14] In addition to the avoided costs of energy, these costs must include the prorated share of the aggregate capacity value of such facilities.

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§ 292.304(c) *Factors affecting rates for purchases.*

Capacity Value

An issue basic to this paragraph is the question of recognition of the capacity value of qualifying facilities.

In the proposed rule, the Commission adopted the argument set forth in the Staff Discussion Paper that the proper interpretation of section 210(b) of PURPA requires that the rates for purchases include recognition of the capacity value provided by qualifying cogeneration and small power production facilities. The Commission noted that language used in section 210 of PURPA and the Conference Report as well as in the Federal Power Act supports this proposition.

In the proposed rule, the Commission cited the final paragraph of the Conference Report with regard to section 210 of PURPA:

> The conferees expect that the Commission, in judging whether the electric power supplied by the cogenerator or small power producer will replace future power which the utility would otherwise have to generate itself either through existing capacity or additions to capacity or purchase from other sources, will take into account the reliability of the power supplied by the cogenerator or small power producer by reason of any legally enforceable obligation of such cogenerator or small power producer to supply firm power to the utility.[18]

In addition to that citation, the Commission notes that the Conference Report states that:

> In interpreting the term "incremental costs of alternative energy", the conferees expect that the Commission and the States may look beyond the costs of alternative sources which are instantaneously available to the utility.[19]

Several commenters contended that, since section 210(a)(2) of PURPA provides that electric utilities must "purchase electric energy" from qualifying facilities, the rate for such purchases should not include payments for capacity. The Commission observes that the statutory language used in the Federal Power Act uses the term "electric energy" to describe the rates for sales for resale in interstate commerce. Demand or capacity payments are a traditional part of such rates. The term "electric energy" is used throughout the Act to refer both to electric energy and capacity. The Commission does not find any evidence that the term "electric energy" in section 210 of PURPA was intended to refer only to fuel and operating and maintenance expenses, instead of all of the costs associated with the provision of electric service.

In addition, the Commission notes that to interpret this phrase to include only energy would lead to the conclusion that the rates for sales *to* qualifying facilities could only include the energy component of the rate since section 210 also refers to "electric energy" with regard to such sales. It is the Commission's belief that this was not the intended result. This provides an additional reason to interpret the phrase "electric energy" to include both energy and capacity.

In implementing this statutory standard, it is helpful to review industry practice respecting sales between utilities. Sales of electric power are ordinarily classified as either firm sales, where the seller provides power at the customer's request, or non-firm power sales, where the seller and not the buyer makes the decision whether or not power is to be available. Rates for firm power purchases include payments for the cost of fuel and operating expenses, and also for the fixed costs associated with the construction of generating units needed to provide power at the purchaser's discretion. The degree of certainty of deliverability required to constitute "firm power" can ordinarily be obtained only if a utility has several generating units and adequate reserve capacity. The capacity payment, or demand charge, will reflect the cost of the utility's generating units.

In contrast, the ability to provide electric power at the selling utility's discretion imposes no requirement that the seller construct or reserve capacity. In order to provide power to customers at the seller's discretion, the selling utility need only charge for the cost of operating its generating units and administration. These costs, called "energy" costs, ordinarily are the ones associated with non-firm sales of power.

Purchases of power from qualifying facilities will fall somewhere on the continuum between these two types of electric service. Thus, for example, wind machines that furnish power only when wind velocity exceeds twelve miles per hour may be so uncertain in availability of output that they would only permit a utility to avoid generating an equivalent amount of energy. In that situation, the utility must continue to provide capacity that is available to meet the needs of its customers. Since there are no avoided capacity costs, rates for such sporadic purchases should thus be based on the utility system's avoided incremental cost of energy. On the other hand, testimony at the Commission's public hearings indicated that effective amounts of firm capacity exist for dispersed wind systems, even though each machine, considered separately, could not provide capacity value. The aggregate capacity value of such facilities must be considered in the calculation of rates for purchases, and the payment distributed to the class providing the capacity.

Some technologies, such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based, in part, on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance of some capacity value and an energy component that reflects the avoided energy costs at the time of the peak.

A facility burning municipal waste or biomass may be able to operate more predictably and reliably than solar or wind systems. It can schedule its outages during times when demand on the utility's system is low. If such a unit demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs.

In order to defer or cancel the construction of new generating units, a utility must obtain a commitment from a qualifying facility that provides contractual or other legally enforceable assurances that capacity from alternative sources will be available sufficiently ahead of the date on which the utility would otherwise have to commit itself to the construction or purchase of new capacity. If a qualifying facility provides such assurances, it is entitled to receive rates based on the capacity costs that the utility can avoid as a result of its obtaining capacity from the qualifying facility.

Other comments with regard to the requirement to include capacity payments in avoided costs generally track those set forth in the Staff Discussion Paper and the proposed rule. The thrust of these comments is that, in order to receive credit for capacity and to comply with the requirement that rates for purchases not exceed the incremental cost of alternative energy, capacity payments can only be required when the availability of capacity from a qualifying facility or facilities actually permits the purchasing utility to reduce

[18] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

[19] *Id.*, pp. 98–9.

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its need to provide capacity by deferring the construction of new plant or commitments to firm power purchase contracts. In the proposed rule, the Commission stated that if a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating plant, to enable it to build a smaller, less expensive plant, or to purchase less firm power from another utility than it would otherwise have purchased, then the rates for purchases from the qualifying facility must include the avoided capacity and energy costs. As indicated by the preceding discussion, the Commission continues to believe that these principles are valid and appropriate, and that they properly fulfill the mandate of the statute.

The Commission also continues to believe, as stated in the proposed rule, that this rulemaking represents an effort to evolve concepts in a newly developing area within certain statutory constraints. The Commission recognizes that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and is one which by definition, is based on estimation and forecasting of future occurrences. Accordingly, the Commission supports the recommendation made in the Staff Discussion Paper that it should leave to the States and nonregulated utilities "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

§ 292.304(e) *Factors affecting rates for purchases.*

As noted previously, several commenters observed that the utility system cost data required under § 292.302 cannot be directly applied to rates for purchase. The Commission acknowledges this point and, as discussed previously, has provided that these data are to be used as a starting point for the calculation of an appropriate rate for purchases equal to the utility's avoided cost. Accordingly, the Commission has removed the reference to the utility system cost data from the definition of rates for purchases, and has inserted the reference to these data in paragraph (e), as one factor to be considered in calculating rates for purchases. Subparagraph (1) states that these data shall, to the extent practicable, be taken into account in the calculation of a rate for purchases.

Subparagraph (2) deals with the availability of capacity from a qualifying facility during system daily and seasonal peak periods. If a qualifying facility can provide energy to a utility during peak periods when the electric utility is running its most expensive generating units, this energy has a higher value to the utility than energy supplied during off-peak periods, during which only units with lower running costs are operating.

The preamble to the proposed rule provided that, to the extent that metering equipment is available, the State regulatory authority or nonregulated electric utility should take into account the time or season in which the purchase from the qualifying facility occurs. Several commenters interpreted this statement as implying that, by refusing to install metering equipment, an electric utility could avoid the obligation to consider the time at which purchases occur. This is not the intent of this provision. Clearly, the more precisely the time of purchase is recorded the more exact the calculation of the avoided costs, and thus the rate for purchases, can be. Rather than specifying that exact time-of-day or seasonal rates for purchases are required, however, the Commission believes that the selection of a methodology is best left to the State regulatory authorities and nonregulated electric utilities charged with the implementation of these provisions.

Clauses (i) through (v) concern various aspects of the reliability of a qualifying facility. When an electric utility provides power from its own generating units or from those of another electric utility, it normally controls the production of such power from a central location. The ability to so control power production enhances a utility's ability to respond to changes in demand, and thereby enhances the value of that power to the utility. A qualifying facility may be able to enter into an arrangement with the utility which gives the utility the advantage of dispatching the facility. By so doing, it increases its value to the utility. Conversely, if a utility cannot dispatch a qualifying facility, that facility may be of less value to the utility.

Clause (ii) refers to the expected or demonstrated reliability of a qualifying facility. A utility cannot avoid the construction or purchase of capacity if it is likely that the qualifying facility which would claim to replace such capacity may go out of service during the period when the utility needs its power to meet system demand. Based on the estimated or demonstrated reliability of a qualifying facility, the rate for purchases from a qualifying facility should be adjusted to reflect its value to the utility.

Clause (iii) refers to the length of time during which the qualifying facility has contractually or otherwise guaranteed that it will supply energy or capacity to the electric utility. A utility-owned generating unit normally will supply power for the life of the plant, or until it is replaced by more efficient capacity. In contrast, a cogeneration or small power production unit might cease to produce power as a result of changes in the industry or in the industrial processes utilized. Accordingly, the value of the service from the qualifying facility to the electric utility may be affected by the degree to which the qualifying facility ensures by contract or other legally enforceable obligation that it will continue to provide power. Included in this determination, among other factors, are the term of the commitment, the requirement for notice prior to termination of the commitment, and any penalty provisions for breach of the obligation.

In order to provide capacity value to an electric utility a qualifying facility need not necessarily agree to provide power for the life of the plant. A utility's generation expansion plans often include purchases of firm power from other utilities in years immediately preceding the addition of a major generation unit. If a qualifying facility contracts to deliver power, for example, for a one year period, it may enable the purchasing utility to avoid entering into a bulk power purchase arrangement with another utility. The rate for such a purchase should thus be based on the price at which such power is purchased, or can be expected to be purchased, based upon bona fide offers from another utility.

Clause (iv) addresses periods during which a qualifying facility is unable to provide power. Electric utilities schedule maintenance outages for their own generating units during periods when demand is low. If a qualifying facility can similarly schedule its maintenance outages during periods of low demand, or during periods in which a utility's own capacity will be adequate to handle existing demand, it will enable the utility to avoid the expenses associated with providing an equivalent amount of capacity. These savings should be reflected in the rate for purchases

Clause (v) refers to a qualifying facility's ability and willingness to provide capacity and energy during system emergencies. Section 292.307 of these regulations concerns the provision of electric service during system emergencies. It provides that to the extent that a qualifying facility is willing to forego its own use of energy during system emergencies and provide power to a utility's system, the rate for purchases from the qualifying facility should reflect the value of that service Small power production and cogeneration facilities could provide significant back-up capability to electric systems during emergencies. One benefit of the encouragement of interconnected cogeneration and small power production may be to increase overall system reliability during such emergency conditions. Any such benefit should be reflected in the rate for purchases from such qualifying facilities.

Another related factor which affects the capacity value of a qualifying facility is its ability to separate its load from its generation during system emergencies. During such emergencies an electric utility may institute load shedding procedures which may, among other things, require that industrial customers or other large loads stop receiving power. As a result, to provide optimal benefit to a utility in an emergency situation, a qualifying facility might be required to continue operation as a generating plant, while simultaneously ceasing operation as a load on the utility's system. To the extent that a facility is unable to separate its load from its generation, its value to the purchasing utility decreases during system emergencies. To reflect such a possibility, clause (v) provides that the purchasing utility may consider the qualifying facility's ability to separate its load from its generation during system emergencies in determining the value of the qualifying facility to the electric utility.

Clause (vi) refers to the aggregate capability of capacity from qualifying facilities to displace planned utility capacity. In some instances, the small amounts of capacity provided from qualifying facilities taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual qualifying facility may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.

Clause (vii) refers to the fact that the lead time associated with the addition of capacity from qualifying facilities may be less than the lead time that would have been required if the purchasing utility had constructed its own generating unit. Such reduced lead time might produce savings in the utility's total power production costs, by permitting utilities to avoid the "lumpiness," and temporary excess capacity associated therewith, which normally occur when utilities bring on line large generating units. In addition, reduced lead time provides the utility with greater flexibility with which it can accommodate changes in forecasts of peak demand.

Subparagraph (3) concerns the relationship of energy or capacity from a qualifying facility to the purchasing electric utility's need for such energy or capacity. If an electric utility has sufficient capacity to meet its demand, and is not planning to add any new capacity to its system, then the availability of capacity from qualifying facilities will not immediately enable the utility to avoid any capacity costs. However, an electric utility system with excess capacity may nevertheless plan to add new, more efficient capacity to its system. If purchases from qualifying facilities enable a utility to defer or avoid these new planned capacity additions, the rate for such purchases should reflect the avoided costs of these additions. However, as noted by several commenters, the deferral or avoidance of such a unit will also prevent the substitution of the lower energy costs that would have accompanied the new capacity. As a result, the price for the purchase of energy and capacity should reflect these lower avoided energy costs that the utility would have incurred had the new capacity been added.

This is not to say that electric utilities which have excess capacity need not make purchases from qualifying facilities; qualifying facilities may obtain payment based on the avoided energy costs on a purchasing utility's system. Many utility systems with excess capacity have intermediate or peaking units which use high-cost fossil fuel. As a result, during peak hours, the energy costs on the systems are high, and thus the rate to a qualifying utility from which the electric utility purchases energy should similarly be high.

Subparagraph (4) addresses the costs or savings resulting from line losses. An appropriate rate for purchases from a qualifying facility should reflect the cost savings actually accruing to the electric utility. If energy produced from a qualifying facility undergoes line losses such that the delivered power is not equivalent to the power that would have been delivered from the source of power it replaces, then the qualifying facility should not be reimbursed for the difference in losses. If the load served by the qualifying facility is closer to the qualifying facility than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.

§ 292.304(f) Periods during which purchase are not required.

The proposed rule provided that an electric utility will not be required to purchase energy and capacity from qualifying facilities during periods in which such purchases will result in net increased operating costs to the electric utility. This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when the system demand later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output.

The result of such a transaction would be that rather than avoiding costs as a result of the purchase from a qualifying facility, the purchasing electric utility would incur greater costs than it would have had it not purchased energy or capacity from the qualifying facility. A strict application of the avoided cost principle set forth in this section would assess these additional costs as negative avoided costs which must be reimbursed by the qualifying facility. In order to avoid the anomalous result of forcing a qualifying utility to pay an electric utility for purchasing its output, the Commission proposed that an electric utility be required to identify periods during which this situation would occur, so that the qualifying facility could cease delivery of electricity during these periods.

Many of the comments received reflected a suspicion that electric utilities would abuse this paragraph to circumvent their obligation to purchase from qualifying facilities. In order to minimize that possibility, the Commission has revised this paragraph

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to provide that any electric utility which seeks to cease purchasing from qualifying facilities must notify each affected qualifying facility prior to the occurrence of such a period, in time for the qualifying facility to cease delivery of energy or capacity to the electric utility. This notification can be accomplished in any reasonable manner determined by the State regulatory authority. Any claim by an electric utility that such a light loading period will occur or has occurred is subject to such verification by its State regulatory authority as the State authority determines necessary or appropriate either before or after its occurrence. Moreover, any electric utility which fails to provide adequate notice or which incorrectly identifies such a period will be required to reimburse the qualifying facility for energy or capacity supplied as if such a light loading period had not occurred.

The section has also been modified to clarify that such periods must be due to operational circumstances.

The Commission does not intend that this paragraph override contractual or other legally enforceable obligations incurred by the electric utility to purchase from a qualifying facility. In such arrangements, the established rate is based on the recognition that the value of the purchase will vary with the changes in the utility's operating costs. These variations ordinarily are taken into account, and the resulting rate represents the average value of the purchase over the duration of the obligation. The occurrence of such periods may similarly be taken into account in determining rates for purchases.

Tax Issues

The Conference Report states that:

> * * * the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or the small power producer's power should not be burdened by the same examination as are utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[17]

The Commission notes that section 301(b)(2) of the Energy Tax Act of 1978 [18] makes certain energy property eligible for increased business investment tax credit. Some of this property is commonly used in cogeneration and small power production. However, section 301(b)(2)(3) excludes from such eligibility property "which is public utility property (within the meaning of section 46(f)(5) of the Internal Revenue Code of 1954)." [19] As a result, if the property of a qualifying facility which was otherwise eligible for the credit were to be classified as public utility property under section 46(f)(5) of the Internal Revenue Code, it would not be eligible for the increased investment tax credit.

The Commission notes that the Treasury Department's regulations provide that the definition of "public utility property" does not include property used in the business of the furnishing or sale of electric energy if the rates are not subject to regulation that fixes a rate of return on investment.[20] On this basis, the Commission believes that property of a qualifying facility that would otherwise be eligible for the energy tax credit would not be excluded from that eligibility under the public utility property exclusion.

First, this Commission is exempting property of qualifying facilities from regulation under Part II of the Federal Power Act, and from similar State and local laws and regulatory programs. Secondly, the Commission observes that the rates a qualifying facility will receive for sales of power to utilities are *not* based on a regulatory scheme which fixes a rate of return on investment of the qualifying facility.

As a result, the Commission believes that energy property of qualifying facilities should not be barred from eligibility for the tax credit by reason of the public utility property exclusion. The Commission wishes to express its opinion on this matter in an effort to further encourage cogeneration and small power production by means of this rulemaking process.

§ 292.305 *Rates for sales.*

Section 210(c) of PURPA provides that the rules requiring utilities to sell electric energy to qualifying facilities shall ensure that the rates for such sales are just and reasonable, in the public interest, and nondiscriminatory with respect to qualifying cogenerators or small power producers. This section contemplates formulation of rates on the basis of traditional ratemaking (*i.e.*, cost-of-service) concepts.

Paragraph (a) expresses the statutory requirement that such rates be just and reasonable and in the public interest. Paragraph (a) also provides that rates for sales from electric utilities to qualifying facilities not be discriminatory against such facilities in comparison to rates to other customers served by the electric utility.

A qualifying facility is entitled to purchase back-up or standby power at a nondiscriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. Thus, where the utility must reserve capacity to provide service to a qualifying facility, the costs associated with that reservation are properly recoverable from the qualifying facility, if the utility would similarly assess these costs to non-generating customers.

In the proposed rule, paragraph (b) required electric utilities to provide energy and capacity and other services to any qualifying facility at a rate at least as favorable as would be provided to a customer who does not have his own generation. The comments received concerning this paragraph noted that this provision might be interpreted as requiring an electric utility to provide service to a qualifying facility at its most favorable rate, even if the qualifying facility would not be eligible for such a rate if it did not have its own generation. It is not the Commission's intention that, for example, an industrial cogenerator receive service at a rate applicable to residential customers; rather, such a customer should be charged at a rate applicable to a non-generating industrial customer unless the electric utility shows that a different rate is justified on the basis of sufficient load or other cost-related data. Accordingly, this section now provides that for qualifying facilities which do not simultaneously sell and purchase from the electric utility, the rate for sales shall be the rate that would be charged to the class to which the qualifying facility would be assigned if it did not have its own generation.

Subparagraph (2) provides that if, on the basis of accurate data and consistent system-wide costing principles, the utility demonstrates that the rate that would be charged to a comparable customer without its own generation is not appropriate, the utility may base its rates for sales upon those data and principles. The utility may only charge such rates on a nondiscriminatory basis, however, so that a cogenerator will not be singled out to lose any interclass or intraclass subsidies to which it might have been entitled had it not generated part of its electric energy needs itself.

In situations where a qualifying facility simultaneously sells its output to an electric utility and purchases its requirements from that electric utility, as a bookkeeping matter, the facility's

[17] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

[18] Pub. L. No. 95-618, 26 U.S.C. §§ 46, 48, November 9, 1978.

[19] 26 U.S.C. § 46(e)(3)(b).

[20] Treasury Reg. § 1.48-3(g)(2), T.D. 7602 (March 23, 1979).

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electrical output will not serve its own load, but rather will be supplied to the grid. As a result, the facility's electric load is likely to have the same characteristics as the load of other non-generating customers of the utility. If the utility does not provide data showing otherwise, the appropriate rate for sales to such a facility is the rate that would be charged to a comparable customer without its own generation.

Paragraph (b)(2) of the rule sets forth certain types of service which electric utilities are required to provide qualifying facilities upon request of the facility. These types of service are supplementary power, back-up power, interruptible power and maintenance power. In response to comments, these terms are defined in the text of the rules, as well as in this preamble.

Back-up or maintenance service provided by an electric utility replaces energy or capacity which a qualifying facility ordinarily supplies to itself. These rules authorize certain facilities to purchase and sell simultaneously. The amount of energy or capacity provided by an electric utility to meet the load of a facility which simultaneously purchases and sells will vary only in accordance with changes in the facility's load; interruptions in the facility's generation will be manifested as variations in purchases from the facility. In such a case, sales to the qualifying facility will not be back-up or maintenance service, but will be similar to the full-requirements service that would be provided if the facility were a non-generating customer.

Supplementary power is electric energy or capacity used by a facility in addition to that which it ordinarily generates on its own. Thus, a cogeneration facility with a capacity of ten megawatts might require five more megawatts from a utility on a continuing basis to meet its electric load of fifteen megawatts. The five megawatts supplied by the electric utility would normally be provided as supplementary power.

Back-up power is electric energy or capacity available to replace energy generated by a facility's own generation equipment during an unscheduled outage. In the example provided above, a cogeneration facility might contract with an electric utility for the utility to have available ten megawatts, should the cogenerator's units experience an outage.

Maintenance power is electric energy or capacity supplied during scheduled outages of the qualifying facility. By pre-arrangement, a utility can agree to provide such energy during periods when the utility's other load is low, thereby avoiding the imposition of large demands on the utility during peak periods.

Interruptible power is electric energy or capacity supplied to a qualifying facility subject to interruption by the electric utility under specified conditions. Many utilities have utilized interruptible service to avoid expensive investment in new capacity that would otherwise be necessary to assure adequate reserves at time of peak demand. Under this approach utilities assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity. Interruptible service is therefore normally provided at a lower rate than non-interruptible service.

During the Commission's public hearings on this rulemaking, one commenter stated that utilities which have excess capacity do not save any costs by providing interruptible service. The commenter contended that the Commission should not require a utility with excess capacity to offer interruptible service. If a utility is not adding capacity (whether by construction or purchase) to meet anticipated increases in peak demand, the rates charged for interruptible service might appropriately be the same as for non-interruptible services.

The Commission believes that these matters involving the provision of interruptible rates are best handled through the pricing mechanism. However, if as discussed above, interruptible customers provide no savings to the electric utility, the rate for interruptible service need not be lower than the rate for firm service. In such a case, the Commission would consider granting a waiver from this paragraph, under the provisions of § 292.403.

Some comments noted that certain electric utilities do not have any generating capacity, and to require the services listed in subparagraph (1) might place an undue burden on the electric utility. In light of these comments, the State regulatory authorities or the Commission, as the case may be, will allow a waiver of these requirements upon a finding after a showing by the utility to the State regulatory authority or Commission, as the case may be, that provision of these services will impair the utility's ability to render adequate service to its customers or place an undue burden on the electric utility. Notice must be given in the area served by the electric utility, opportunity for public comment must be provided, and an application must be submitted to the State regulatory authority with respect to any electric utility over which it has ratemaking authority or the Commission with respect to any nonregulated electric utility.

Paragraph (c)(1) provides that rates for sales of back-up or maintenance power shall not be based, without factual data, on the assumption that forced outages or other reductions in output by each qualifying facility on an electric utility's system will occur either simultaneously or during the system peak. Like other customers, qualifying facilities may well have intraclass diversity. In addition, because of the variations in size and load requirements among various types of qualifying facilities, such facilities may well have interclass diversity.

The effect of such diversity is that an electric utility supplying back-up or maintenance power to qualifying facilities will not have to plan for reserve capacity to serve such facilities on the assumption that every facility will use power at the same moment. The Commission believes that probabilistic analyses of the demand of qualifying facilities will show that a utility will probably not need to reserve capacity on a one-to-one basis to meet back-up requirements. Paragraph (c)(1) prohibits utilities from basing rates on the assumption that qualifying facilities will impose demands simultaneously and at system peak unless supported by factual data.

The rule provides that utilities may refute these assumptions on the basis of factual data. These data need not be in the form of empirical load data. It might be the case that within certain geographic areas, weather data and performance data would constitute a sufficient basis to refute the assumption relating to the coincidence of the demands imposed, for example, by windmills or photovoltaics, with respect to their need for back-up power.

Paragraph (c)(2) provides that rates for sales shall take into account the extent to which a qualifying facility can usefully coordinate periods of scheduled maintenance with an electric utility. If a qualifying facility stays on line when the utility will need its capacity, and schedules maintenance when the utility's other units are operative, the qualifying facility is more valuable to the utility, as it can reduce its capacity requirements.

§ 292.306 *Interconnection costs.*

Paragraph (a) states that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs, on a nondiscriminatory basis with respect to other customers with similar load characteristics. The Commission finds

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electrical output will not serve its own load, but rather will be supplied to the grid. As a result, the facility's electric load is likely to have the same characteristics as the load of other non-generating customers of the utility. If the utility does not provide data showing otherwise, the appropriate rate for sales to such a facility is the rate that would be charged to a comparable customer without its own generation.

Paragraph (b)(2) of the rule sets forth certain types of service which electric utilities are required to provide qualifying facilities upon request of the facility. These types of service are supplementary power, back-up power, interruptible power and maintenance power. In response to comments, these terms are defined in the text of the rules, as well as in this preamble.

Back-up or maintenance service provided by an electric utility replaces energy or capacity which a qualifying facility ordinarily supplies to itself. These rules authorize certain facilities to purchase and sell simultaneously. The amount of energy or capacity provided by an electric utility to meet the load of a facility which simultaneously purchases and sells will vary only in accordance with changes in the facility's load; interruptions in the facility's generation will be manifested as variations in purchases from the facility. In such a case, sales to the qualifying facility will not be back-up or maintenance service, but will be similar to the full-requirements service that would be provided if the facility were a non-generating customer.

Supplementary power is electric energy or capacity used by a facility in addition to that which it ordinarily generates on its own. Thus, a cogeneration facility with a capacity of ten megawatts might require five more megawatts from a utility on a continuing basis to meet its electric load of fifteen megawatts. The five megawatts supplied by the electric utility would normally be provided as supplementary power.

Back-up power is electric energy or capacity available to replace energy generated by a facility's own generation equipment during an unscheduled outage. In the example provided above, a cogeneration facility might contract with an electric utility for the utility to have available ten megawatts, should the cogenerator's units experience an outage.

Maintenance power is electric energy or capacity supplied during scheduled outages of the qualifying facility. By pre-arrangement, a utility can agree to provide such energy during periods when the utility's other load is low, thereby avoiding the imposition of large demands on the utility during peak periods.

Interruptible power is electric energy or capacity supplied to a qualifying facility subject to interruption by the electric utility under specified conditions. Many utilities have utilized interruptible service to avoid expensive investment in new capacity that would otherwise be necessary to assure adequate reserves at time of peak demand. Under this approach utilities assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity. Interruptible service is therefore normally provided at a lower rate than non-interruptible service.

During the Commission's public hearings on this rulemaking, one commenter stated that utilities which have excess capacity do not save any costs by providing interruptible service. The commenter contended that the Commission should not require a utility with excess capacity to offer interruptible service. If a utility is not adding capacity (whether by construction or purchase) to meet anticipated increases in peak demand, the rates charged for interruptible service might appropriately be the same as for non-interruptible services.

The Commission believes that these matters involving the provision of interruptible rates are best handled through the pricing mechanism. However, if as discussed above, interruptible customers provide no savings to the electric utility, the rate for interruptible service need not be lower than the rate for firm service. In such a case, the Commission would consider granting a waiver from this paragraph, under the provisions of § 292.403.

Some comments noted that certain electric utilities do not have any generating capacity, and to require the services listed in subparagraph (1) might place an undue burden on the electric utility. In light of these comments, the State regulatory authorities or the Commission, as the case may be, will allow a waiver of these requirements upon a finding after a showing by the utility to the State regulatory authority or Commission, as the case may be, that provision of these services will impair the utility's ability to render adequate service to its customers or place an undue burden on the electric utility. Notice must be given in the area served by the electric utility, opportunity for public comment must be provided, and an application must be submitted to the State regulatory authority with respect to any electric utility over which it has ratemaking authority or the Commission with respect to any nonregulated electric utility.

Paragraph (c)(1) provides that rates for sales of back-up or maintenance power shall not be based, without factual data, on the assumption that forced outages or other reductions in output by each qualifying facility on an electric utility's system will occur either simultaneously or during the system peak. Like other customers, qualifying facilities may well have intraclass diversity. In addition, because of the variations in size and load requirements among various types of qualifying facilities, such facilities may well have interclass diversity.

The effect of such diversity is that an electric utility supplying back-up or maintenance power to qualifying facilities will not have to plan for reserve capacity to serve such facilities on the assumption that every facility will use power at the same moment. The Commission believes that probabilistic analyses of the demand of qualifying facilities will show that a utility will probably not need to reserve capacity on a one-to-one basis to meet back-up requirements. Paragraph (c)(1) prohibits utilities from basing rates on the assumption that qualifying facilities will impose demands simultaneously and at system peak unless supported by factual data.

The rule provides that utilities may refute these assumptions on the basis of factual data. These data need not be in the form of empirical load data. It might be the case that within certain geographic areas, weather data and performance data would constitute a sufficient basis to refute the assumption relating to the coincidence of the demands imposed, for example, by windmills or photovoltaics, with respect to their need for back-up power.

Paragraph (c)(2) provides that rates for sales shall take into account the extent to which a qualifying facility can usefully coordinate periods of scheduled maintenance with an electric utility. If a qualifying facility stays on line when the utility will need its capacity, and schedules maintenance when the utility's other units are operative, the qualifying facility is more valuable to the utility, as it can reduce its capacity requirements.

§ 292.308 *Interconnection costs.*

Paragraph (a) states that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs, on a nondiscriminatory basis with respect to other customers with similar load characteristics. The Commission finds merit in those comments which suggested that the basis of comparison for nondiscriminatory practices in the proposed rule to "any other customer" was too broad, and that the correct reference for nondiscrimination is the practice of the utility in relation to customers in the same class who do not generate electricity. As noted previously, the interconnection costs of a facility which is already interconnected with the utility for purposes of sales are limited to any additional expenses incurred by the utility to permit purchases.

Several commenters expressed their concern that some protection should be provided to qualifying facilities from potential harassment by utilities in the form of requiring unnecessary safety equipment. As discussed above, the State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) and nonregulated electric utilities have the responsibility and authority to ensure that the interconnection requirements are reasonable, and that associated costs are legitimately incurred.

For qualifying facilities with a design capacity of 100 kW or less, the Commission noted that interconnection costs could be assessed on a class basis, and the standard rates for purchases established for classes of facilities of this size pursuant to § 292.304(c)(1) might incorporate these costs. State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) or nonregulated electric utilities may also determine interconnection costs for qualifying facilities with a design capacity of more than 100 kW on either a class average or individual basis.

Numerous comments raised the point that the proposed rule did not address the manner in which electric utilities would be reimbursed. Potential owners and developers of qualifying facilities recommended that the costs be amortized on a reasonable basis, because paying a large lump sum payment would be a considerable obstacle to the program. Electric utilities generally preferred payment up front, although several commenters indicated that amortization might be acceptable for credit-worthy facilities. The Commission believes that the manner of reimbursements (which may include amortization over a reasonable period of time) is best left to the State regulatory authorities and nonregulated utilities. In the determination of any standard rates for purchases established pursuant to § 292.304(c)(1), if the State approves some manner of amortization, it might consider assignment of uncollected interconnection costs to the class for which the rate is established.

§ 292.307 System emergencies.

Paragraph (a) provides that, except as provided under section 202(c) of the Federal Power Act, no qualifying facility shall be compelled to provide energy or capacity to the electric utility during an emergency beyond the extent provided by agreement between the qualifying facility and the utility.

The Commission finds that a qualifying facility should not be required to make available all of its generation to the utility during a system emergency. Such a requirement might interrupt industrial processes with resulting damage to equipment and manufactured goods. Many industries install their own generating equipment in order to ensure that even during a system emergency, their supply of power is not interrupted. To put in jeopardy the availability of power to a qualifying facility during a system emergency because of the facility's ability to provide power to the system during non-emergency periods would result in the discouragement of interconnected operation and a resultant discouragement of cogeneration and small power production. The Commission therefore provides that the qualifying facility's obligation to provide energy and capacity in emergencies be established through contract.

In order to receive full credit for capacity, a qualifying facility must offer energy and capacity during system emergencies to the same extent that it has agreed to provide energy and capacity during non-emergency situations. For example, a 30 megawatt cogenerator may require 20 megawatts for its own industrial purposes, and thus may contract to provide 10 megawatts of capacity to the purchasing utility. During an emergency, the cogenerator must provide the 10 megawatts contracted for to the utility; it need not disrupt its industrial processes by supplying its full capability of 30 megawatts. Of course, if it should so desire, a cogenerator could contractually agree to supply the full 30 megawatts during system emergencies. The availability of such additional backup capacity should increase utility system reliability, and should be accounted for in the utility's rates for purchases from the cogenerator.

Paragraph (b) provides that an electric utility may discontinue purchases from a qualifying facility during a system emergency if such purchases would contribute to the emergency. In addition, during system emergencies, a qualifying facility must be treated on a nondiscriminatory basis in any load shedding program—*i.e.*, on the same basis that other customers of a similar class with similar load characteristics are treated with regard to interruption of service.

Credit for capacity (as noted in § 292.304(e)(2)(v)) will also take into account the ability of the qualifying facility to separate its load and generation during system emergencies. However, the qualifying facility may well be eligible for some capacity credit even if it cannot separate its load and generation.

§ 292.308 Standards for operating reliability.

Section 210(a) of PURPA states that the rules requiring electric utilities to buy from and sell to qualifying facilities shall include provisions respecting minimum reliability of qualifying facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric utilities during emergencies. The Commission believes that the reliability of qualifying facilities can be accounted for through price; namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.

As a result, the Commission has not included specific standards relating to the reliability in the sense of the ability of qualifying facilities to provide energy or capacity.

The Commission has determined that safety equipment exists which can ensure that qualifying facilities do not energize utility lines during utility outages. This section accordingly provides that each State regulatory authority or nonregulated electric utility may establish standards for interconnected operation between electric utilities and qualifying facilities. These standards may be recommended by any utility, any qualifying facility, or any other person. These standards must be accompanied by a statement showing the need for the standard on the basis of system safety and operating requirements.

Subpart D—Implementation

Summary of this Subpart

Rules in this subpart are intended to carry out the responsibility of the Commission to encourage cogeneration and small power production by clarifying the nature of the obligation to implement the Commission's rules under section 210.

These rules afford the State regulatory authorities and nonregulated electric utilities great latitude in determining the manner of implementation of the

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Several commenters expressed their concern that some protection should be provided to qualifying facilities from potential harassment by utilities in the form of requiring unnecessary safety equipment. As discussed above, the State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) and nonregulated electric utilities have the responsibility and authority to ensure that the interconnection requirements are reasonable, and that associated costs are legitimately incurred.

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Numerous comments raised the point that the proposed rule did not address the manner in which electric utilities would be reimbursed. Potential owners and developers of qualifying facilities recommended that the costs be amortized on a reasonable basis, because paying a large lump sum payment would be a considerable obstacle to the program. Electric utilities generally preferred payment up front, although several commenters indicated that amortization might be acceptable for credit-worthy facilities. The Commission believes that the manner of reimbursements (which may include amortization over a reasonable period of time) is best left to the State regulatory authorities and nonregulated utilities. In the determination of any standard rates for purchases established pursuant to § 292.304(c)(1), if the State approves some manner of amortization, it might consider assignment of uncollected interconnection costs to the class for which the rate is established.

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Credit for capacity (as noted in § 292.304(e)(2)(v)) will also take into account the ability of the qualifying facility to separate its load and generation during system emergencies. However, the qualifying facility may well be eligible for some capacity credit even if it cannot separate its load and generation.

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Section 210(a) of PURPA states that the rules requiring electric utilities to buy from and sell to qualifying facilities shall include provisions respecting minimum reliability of qualifying facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric utilities during emergencies. The Commission believes that the reliability of qualifying facilities can be accounted for through price: namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.

As a result, the Commission has not included specific standards relating to the reliability in the sense of the ability of qualifying facilities to provide energy or capacity.

The Commission has determined that safety equipment exists which can ensure that qualifying facilities do not energize utility lines during utility outages. This section accordingly provides that each State regulatory authority or nonregulated electric utility may establish standards for interconnected operation between electric utilities and qualifying facilities. These standards may be recommended by any utility, any qualifying facility, or any other person. These standards must be accompanied by a statement showing the need for the standard on the basis of system safety and operating requirements.

Subpart D—Implementation

Summary of this Subpart

Rules in this subpart are intended to carry out the responsibility of the Commission to encourage cogeneration and small power production by clarifying the nature of the obligation to implement the Commission's rules under section 210.

These rules afford the State regulatory authorities and nonregulated electric utilities great latitude in determining the manner of implementation of the

Commission's rules, provided that the manner chosen is reasonably designed to implement the requirements of Subpart C. The Commission recognizes that many States and individual nonregulated electric utilities have ongoing programs to encourage small power production and cogeneration. The Commission also recognizes that economic and regulatory circumstances vary from State to State and utility to utility. It is within this context—in recognition of the work already begun and of the variety of local conditions—that the Commission promulgates its regulations requiring implementation of rules issued under section 210.

Because of the Commission's desire not to create unnecessary burdens at the State level, these rules provide a procedure whereby a State regulatory authority or nonregulated electric utility may apply to the Commission for a waiver if it can demonstrate that compliance with certain requirements of Subpart C is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210.

Several commenters expressed their concern that State regulatory authorities would not be able adequately to implement the Commission's rules, and therefore, recommended that the Commission issue specific rules which the State regulatory authorities would adopt without change. The Commission does not find this proposal to be appropriate at this time, and believes that providing an opportunity for experimentation by the States is more conducive to development of these difficult rate principles.

Implementation

Section 210(f) of PURPA requires that within one year after the date that this Commission prescribes its rules under subsection (a), and within one year of the date any of these rules is revised, each State regulatory authority and each nonregulated electric utility, after notice and opportunity for hearing, must implement the rules or revisions thereof, as the case may be.

The obligation to implement section 210 rules is a continuing obligation which begins within one year after promulgation of such rules. The requirement to implement may be fulfilled either (1) through the enactment of laws or regulations at the State level, (2) by application on a case-by-case basis by the State regulatory authority, or nonregulated utility, of the rules adopted by the Commission, or (3) by any other action reasonably designed to implement the Commission's rules.

Review and Enforcement

Section 210(g) of PURPA provides one of the means of obtaining judicial review of a proceeding conducted by a State regulatory authority or nonregulated utility for purposes of implementing the Commission's rules under section 210. Under subsection (g), review may be obtained pursuant to procedures set forth in section 123 of PURPA. Section 123(c)(1) contains provisions concerning judicial review and enforcement of determinations made by State regulatory authorities and nonregulated utilities under Subtitle A, B, or C of Title I in the appropriate State court. These provisions also apply to review of any action taken to implement the rules under section 210. This means that persons can bring an action in State court to require the State regulatory authorities or nonregulated utilities to implement these regulations.

Section 123(c)(2) of PURPA provides that persons seeking review of any determination made by a Federal agency may bring an action in the appropriate Federal court. This distinction between Federal agencies and non-Federal agencies also applies to review of enforcement of the implementation of the rules under section 210.

Finally, the Commission believes that review and enforcement of implementation under section 210 of PURPA can consist not only of review and enforcement as to whether the State regulatory authority or nonregulated electric utility has conducted the initial implementation properly—namely, put into effect regulations implementing section 210 rules or procedures for that implementation, after notice and an opportunity for a hearing. It can also consist of review and enforcement of the application by a State regulatory authority or nonregulated electric utility, on a case-by-case basis, of its regulations or of any other provision it may have adopted to implement the Commission's rules under section 210.

Section 210(h)(2)(A) of PURPA states that the Commission may enforce the implementation of regulations under section 210(f). The Congress has provided not only for private causes of action in State courts to obtain judicial review and enforcement of the implementation of the Commission's rules under section 210, but also provided that the Commission may serve as a forum for review and enforcement of the implementation of this program.

§ 292.401 Implementation by state regulatory authorities and nonregulated electric utilities

Paragraph (a) of § 292.401 sets forth the obligation of each State regulatory authority to commence implementation of Subpart C within one year of the date these rules take effect. In complying with this paragraph the State regulatory authorities are required to provide for notice of and opportunity for public hearing. As described in the summary of this subpart, such implementation may consist of the adoption of the Commission's rules, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement Subpart C.

This section does not cover one provision of Subpart C which is not required to be implemented by the State regulatory authority or nonregulated electric utility. This provision is § 292.302 (Availability of electric utility system cost data), the implementation of which is subject to § 292.402, discussed below.

Subsection (b) sets forth the obligation of each nonregulated electric utility to commence, after notice and opportunity for public hearing, implementation of Subpart C. The nonregulated electric utilities, being both the regulator and the utility subject to the regulation, may satisfy the obligation to commence implementation of Subpart C through issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement that subpart.

Paragraph (c) sets forth a reporting requirement under which each State regulatory authority and nonregulated electric utility is to file with the Commission, not later than one year after these rules take effect, a report describing the manner in which it is proceeding to implement Subpart C.

Comments received regarding this section indicated a concern that the obligation of a State regulatory authority or nonregulated utility "to commence implementation * * * within one year * * *" did not provide any guidance as to when the process must be completed. The Commission notes that the intention of this section is that the State regulatory authorities and nonregulated utilities have one year in which to establish procedures and that at the end of that year each State must be prepared to [illegible] applications. The phrase "commence implementation" is intended by the Commission to connote that implementation of these rules is a

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continuing process and that oversight will be ongoing.

§ 292.402 Implementation of reporting objectives.

The obligation to comply with § 292.302 is imposed directly on electric utilities. This is different from the rest of Subpart C where the obligation to act is imposed on the State regulatory authority or the nonregulated electric utility in its role as regulator. The Commission is exercising its authority under section 133 of PURPA and other laws within the Commission's authority to require this reporting.

Any electric utility which fails to comply with the requirements of § 292.302(b) is subject to the same penalties as it might receive as a result of a failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA. As stated earlier in this preamble, the data required by § 292.302 will form the basis from which the rates for purchases will be derived: § 292.302 is thus a critical element in this program. The Commission believes that, with regard to utilities subject to section 133 of PURPA, the Commission may exercise its authority under section 133 to require the data required by § 292.302(b) on the basis that the Commission finds such information necessary to allow determination of the costs associated with providing electric services. With regard to utilities not subject to section 133, if they fail to provide the data called for in § 292.302(c), the Commission may compel its production under the Federal Power Act and other statutes which provide the Commission with authority to require reporting of such data.

§ 292.403 Waivers.

Paragraph (a) provides for a procedure by which any State regulatory authority or nonregulated electric utility may apply for a waiver from the application of any of the requirements of Subpart C other than § 292.302. (Section 292.302(d) has been revised to permit a State regulatory authority or nonregulated utility to adopt a substitute method for the provision of system cost data without prior Commission approval.)

Paragraph (b) provides that the Commission will grant such a waiver only if the applicant can show that compliance with any of the requirements is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210 of PURPA.

This section is included in recognition of the need for the Commission to afford flexibility to the States and nonregulated utilities to implement the Commission's rules under section 210.

Several comments suggested that the Commission set forth procedures for considering applications for waivers which would allow formal participation by qualifying facilities in a public hearing. The Commission notes that interested parties would be given an opportunity to be heard in any proceeding it conducts to determine whether or not a waiver should be granted.

Subpart F—Exemption of Qualifying Small Power Production and Cogeneration Facilities From Certain Federal and State Laws and Regulations

§ 292.601 Exemption of qualifying facilities from the Federal Power Act.

Section 210(e) of PURPA states that the Commission shall prescribe rules under which qualifying facilities are exempt, in part, from the Federal Power Act, from the Public Utility Holding Company Act of 1935, from the State laws and regulations respecting the rates, or respecting the financial or organization regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. As noted in the Staff Discussion Paper, the Congress intended the Commission to make liberal use of its exemption authority in order to remove the disincentive of utility-type regulation. The Commission believes that broad exemption is appropriate.

Section 210(e)(2) of PURPA provides that the Commission is not authorized to exempt small power production facilities of 30 to 80 megawatt capacity from these laws. An exception is made for small power production facilities using biomass as a primary energy source. Such facilities between 30 and 80 megawatts may be exempted from the Public Utility Holding Company Act of 1935 and from State laws and regulations but may not be exempted from the Federal Power Act. The Commission will establish procedures for the determination of rates for these facilities in a separate proceeding.

Paragraph (a) sets forth those facilities which are eligible for exemption. Paragraph (b) provides that facilities described in paragraph (a) shall be exempted from all but certain specified sections of the Federal Power Act.

Section 210(e)(3)(C) of PURPA provides that no qualifying facility may be exempted from any license or permit requirement under Part I of the Federal Power Act. Accordingly, no qualifying facilities will be exempt from Part I of the Federal Power Act. The Commission recently issued simplified procedures for obtaining water power licenses for hydroelectric projects of 1.5 megawatts or less, and has issued proposed regulations to expedite licensing of existing facilities.[31]

The Commission believes cogeneration and small power production facilities could be the subject of an order under section 202(c) of the Federal Power Act requiring them to provide energy if the Economic Regulatory Administration determines that an emergency situation exists. Because application of this section is limited to emergency situations and is not affected by the fact that a facility attains qualifying status or engages in interchanges with an electric utility, the Commission notes that qualifying facilities will not be exempted from section 202(c) of the Act.

Furthermore, in response to comment, the Commission has revised this paragraph to provide that qualifying facilities are not exempt from sections 210, 211, and 212 of the Federal Power Act, as required by section 210(e)(3)(B) of PURPA.

Sections 203, 204, 205, 206, 208, 301, 302, and 304 of the Federal Power Act reflect traditional rate regulation or regulation of securities of public utilities. The Commission has determined that qualifying facilities shall be exempted from these sections of the Federal Power Act.

Section 305(c) of the Act imposes certain reporting requirements on interlocking directorates. The Commission believes that any person who otherwise is required to file a report regarding interlocking positions should not be exempted from such requirement because he or she is also a director or officer of a qualifying facility.

Finally, the enforcement provisions of Part III of the Federal Power Act will continue to apply with respect to the sections of the Federal Power Act from which qualifying facilities are not exempt.

§ 292.602 Exemption of qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

Under section 210(e) of PURPA the Commission can exempt qualifying facilities from regulation under the

[31] See Order No. 11, Simplified Procedures for Certain Water Power Licenses, Docket No. RM79-9, issued September 5, 1978, and Application for License for Major Projects—Existing Dam, Docket No. RM79-36, 44 FR 24085 (April 21, 1979).

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Public Utility Holding Company Act of 1935 and State laws and regulations concerning rates or financial organization. Only cogeneration facilities and small power production facilities of 30 megawatts or less may be exempted from both of these laws, with the exception that any qualifying small power production facility (*i.e.*, up to 80 megawatts) using biomass as a primary energy source can be exempted from these laws.

The Commission has determined that where a qualifying facility is subjected to more stringent regulation than other companies solely by reason of the fact that it is engaged in the production of electric energy, these more stringent requirements should be eased through exemption of qualifying facilities. By excluding any qualifying facility from the definition of an "electric utility company" under section 2(a)(3) of the Public Utility Holding Company Act of 1935, such facilities would be removed from Public Utility Holding Company Act regulation which is applied exclusively to electric utility companies. Moreover, by excluding qualifying facilities from this definition, parent companies of qualifying facilities would not be subject to additional regulation as a result of electric production by their subsidiaries. The Commission therefore believes that in order to encourage cogeneration and small power production it is necessary to exempt cogenerators and small power producers from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities.

Accordingly, paragraph (b) states that no qualifying facility shall be considered to be an "electric utility company", as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79b(a)(3).

Section 210(e) of PURPA states that qualifying facilities which may be exempted from the Public Utility Holding Company Act may also be exempted from State laws and regulations respecting the rates or financial organization of electric utilities.

The Commission has decided to provide a broad exemption from State laws and regulations which would conflict with the State's implementation of the Commission's rules under section 210.

The Commission believes that such broad exemption is necessary to encourage cogeneration or small power production. Accordingly, subparagraph (c)(1) provides that any qualifying facility shall be exempt from State laws and regulations respecting rates of electric utilities, and from financial and organizational regulation of electic utilities. Several commenters noted that this section might be interpreted as exempting qualifying facilities from state laws or regulations implementing the Commission's rules, under section 210(f) of PURPA. In order to clarify that qualifying facilities are not to be exempt from these rules, the Commission has added subparagraph (c)(2) prohibiting any exemptions from State laws and regulations promulgated pursuant to Subpart C of these rules.

Some commenters indicated that § 292.301(b)(1) might be interpreted as prohibiting a State from reviewing contracts for purchases. These commenters stated that, as a part of a State's regulation of electric utilities, a State regulatory authority needs to be able to review contracts entered into by electric utilities it regulates.

These rules, and the exemptions being provided by these rules, are not intended to divest a State regulatory agency of its authority under State law to review contracts for purchases as part of its regulation of electric utilities. Such authority may continue to be exercised if consistent with the terms, policies and practices under sections 210 and 201 of PURPA and this Commission's implementing regulations. If the authority or its exercise is in conflict with these sections of PURPA or the Commission's regulations thereunder, the State must yield to the Federal requirements. The Commission does not believe it possible or advisable to attempt to establish more precise guidelines than these. Accordingly, States which have questions in this regard should seek an interpretive ruling from the Commission's General Counsel.

Subparagraph (c)(3) provides that, upon request of a State regulatory authority or nonregulated electric utility, the Commission may limit the applicability of the broad exemption from the State laws. This provision is intended to add flexibility to the exemption.

The Commission perceives that there may be instances in which a qualifying facility would wish to have an interpretation of whether or not it is subject to a particular State law in order to remove any uncertainty. Under subparagraph (c)(4), the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 Fed. Reg. 46267)

IV. Effective Date

The regulations promulgated in this order are effective March 20, 1980.

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective March 20, 1980. By the Commission.

Kenneth F. Plumb,
Secretary.

(1) Subchapter K is amended in the table of contents and in the text of the regulation by deleting the title for Part 292 and substituting the following in lieu thereof:

Part 292—Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 With Regard to Small Power Production and Cogeneration.

(2) Subchapter K is further amended in the table of contents to Part 292 and in the text of the regulations by reserving Subpart B and by adding new Subparts A, C, D, and F to read as follows:

PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION

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Act and Certain State Law and Regulation.

Authority: This part issued under the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 FR 46267.

Subpart A—General Provisions

§ 292.101 Definitions.

(a) *General rule.* Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they have under PURPA, unless further defined in this part.

(b) *Definitions.* The following definitions apply for purposes of this part.

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of this part of the Commission's regulations.

(2) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(3) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(4) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

(7) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(8) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(9) "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(10) "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(11) "Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Subpart B—[Reserved]

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§ 292.301 Scope.

(a) *Applicability.* This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

§ 292.302 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until May 31, 1982.

(b) *General rule.* To make available data from which avoided costs may be derived, not later than November 1, 1980, May 31, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(c) *Special rule for small electric utilities.*

(1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility

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and the rates at which it currently purchases such energy and capacity

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) *Substitution of alternative method.* (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) *State Review.* (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

§ 292.303 Electric utility obligations under this subpart.

(a) *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, any energy and capacity requested by the qualifying facility.

(c) *Obligation to interconnect.* (1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(d) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission.

(e) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

§ 292.304 Rates for purchases.

(a) *Rates for purchases.* (1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) *Relationship to avoided costs.* (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section.

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) *Standard rates for purchases.* (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

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(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) *Periods during which purchases not required.*

(1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.305 Rates for sales.

(a) *General rules.* (1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional Services to be Provided to Qualifying Facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

§ 292.306 Interconnection costs.

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

§ 292.307 System emergencies.

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.308 Standards for operating reliability.

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

Subpart D—Implementation

§ 292.401 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) *State regulatory authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence

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implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(b) *Nonregulated electric utilities.* Not later than one year after these rules take effect, each nonregulated electric utility shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(c) *Reporting requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonreguated electric utility shall file with the Commission a report describing the manner in which it will implement Subpart C (other than § 292.302 thereof).

§ 292.402 Implementation of certain reporting requirements.

Any electric utility which fails to comply with the requirements of § 292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

§ 292.403 Waivers.

(a) *State regulatory authority and nonregulated electric utility waivers.* Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of Subpart C (other than § 292.302 thereof).

(b) *Commission action.* The Commission will grant such a wavier only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of Subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to:

(1) qualifying cogeneration facilities; and

(2) qualifying small power production facilities which have a power production capacity which does not exceed 30 megawatts.

(b) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Sections 1–30;

(2) Sections 202(c), 210, 211, and 212;

(3) Sections 305(c); and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (b) (1), (2) and (3) of this section.

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(c) *Exemption from certain State law and regulation.*

(1) Any qualifying facility shall be exempted (except as provided in paragraph (c)(2)) of this section from State law or regulation respecting:

(i) The rates of electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State law and regulation implementing Subpart C.

(3) Upon request of a State regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in subparagraph (1).

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

[FR Doc. 80-4720 Filed 2-22-80; 8:45 am]

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18 CFR Part 292

[Docket No. RM79-55]

Rates and Exemptions for Qualifying Small Power Production and Cogeneration Facilities; Correction

April 3, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Erratum notice.

SUMMARY: This notice contains a correction of § 292.302 (a) and (b) of the Federal Energy Regulatory Commission's final regulations.

FOR FURTHER INFORMATION CONTACT: Deborah Gottheil, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357-8000.

SUPPLEMENTARY INFORMATION: In the Federal Energy Regulatory Commission's Final Regulations, issued February 19, 1980, entitled Regulations Under Section 210 of the Public Utility Regulatory Policies Act of 1978 (45 FR 12214, February 25, 1980), at 45 FR 12234, in § 292.302 (a) and (b), the reference to May 31, 1982 should be changed to June 30, 1982. This revision will accurately carry out the Commission's intent, as stated in the preamble to the rule, to "conform to the dates required by the Commission's regulations implementing section 133 of PURPA."

Kenneth F. Plumb,

Secretary.

[FR Doc. 80-10786 Filed 4-8-80; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Docket No. RM79-54]

Small Power Production and Cogeneration Facilities—Qualifying Status

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 201 of the Public Utility Regulatory Policies Act of 1978. These rules set forth criteria and procedures by which small power producers and cogeneration facilities can obtain qualifying status to receive the rate benefits and exemptions set forth in the Commission's rules implementing section 210 of PURPA, which were issued on February 19, 1980 (45 FR 12214, February 25, 1980).

EFFECTIVE DATE: March 13, 1980.

FOR FURTHER INFORMATION CONTACT:

Ross Ain, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8446.
Bernard Chew, Office of Electric Power Regulation, 400 First Street, NE., Washington, D.C., (202) 376-9264.
James Liles, Office of Regulatory Analysis, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8158.
Adam Wenner, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8338.

SUPPLEMENTARY INFORMATION:

March 13, 1980.

Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA) mandates that the Federal Energy Regulatory Commission (Commission) prescribe rules under which small power production facilities and cogeneration facilities can obtain "qualifying" status, and thus become eligible for the rates and exemptions set forth in the Commission's rules implementing section 210 of PURPA.

Section 201 of PURPA[1] defines a "small power production facility" as a facility which:

(1) Produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof; and

(2) Has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts.

A cogeneration facility is defined as a facility which produces electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes.[2]

Thus, cogeneration facilities simultaneously produce two forms of useful energy, namely electric power and heat. Cogeneration facilities can use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. By using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's effort to conserve its energy resources.

Small power production facilities as defined in the Act use biomass, waste, or renewable resources, including wind, solar energy and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume fossil fuels to generate electric power.

Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally willing to purchase the electric output or was not willing to pay an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to extensive State and Federal regulation.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA, and to provide back-up power and other services to such facilities on a non-discriminatory basis. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, which are in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act. Finally, under section 206(c)(3) of the Natural Gas Policy Act of 1978 (NGPA), the Commission may exempt qualifying cogeneration facilities from the incremental pricing program under Title II of the NGPA.

In this rulemaking, the Commission sets forth requirements for qualifying cogeneration and small power production facilities and procedures by which such facilities may obtain qualification. Rules implementing section 210 of PURPA have been prescribed in Docket No. RM79-55.[3]

Any qualifying facility is eligible for the exemptions set forth in Subpart F of this part of the Commission's regulations immediately upon issuance of these rules. With regard to the rate benefits for qualifying facilities found in Subpart C of this part, however, the statute provides that the State regulatory authorities and nonregulated electric utilities will have up to one year to implement the Commission's rules. Therefore, the latest date by which qualifying facilities will be eligible to receive these PURPA-derived rate benefits is February 19, 1981.

I. Procedural History

~~On June 26, 1979, the Commission issued proposed rules in this docket.~~[4] to determine which cogeneration and small power production facilities may become "qualifying" cogeneration or small power production facilities under section 201 of PURPA.

Public hearings on RM79-54 were held in San Francisco on July 23, 1979, Chicago on July 27, 1979, and Washington, D.C. on July 30, 1979. Written comments were also received.

On October 18, 1979, the Commission issued a Notice of Proposed Rulemaking Under Section 210 of PURPA in Docket No. RM79-55.[5] On October 19, 1979, the Commission made available its preliminary Environmental Assessment (EA) of the proposed rules in Docket Nos. RM79-54 and RM79-55.

In a Request for Further Comments,[6] the Commission requested further public

[1] Section 3(17)(A) of the Federal Power Act.

[2] Section 3(18)(A) of the Federal Power Act.

[3] 18 C.F.R. Part 292, Subparts A, C, D and F; 45 FR 12214 (Feb. 25, 1980).

~~[4] [illegible]~~

[5] [illegible] (Oct. [illegible], 1979).

[6] 44 FR 61877 (Oct. 29, 1979).

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comment on both proposed rules, and on the findings set forth in the preliminary EA. In order to obtain the data, views, and arguments of interested persons, the Commission Staff held public hearings in Seattle on November 19, 1979, in New York City on November 28, 1979, in Denver on November 30, 1979, and in Washington, D.C. on December 4 and 5, 1979. The Commission also received written comment. All of the comments were considered in the formulation of this final rule.

II. Summary

These rules set forth criteria and procedures by which cogeneration and small power production facilities can obtain qualifying status to receive the rate benefits and exemptions set forth in the Commission's rules implementing section 210 of PURPA.

The rules in this docket permit qualification without a need for specific Commission action. They also make available an optional procedure under which, should it prove desirable, a facility can gain certification as a "qualifying facility." For qualifying small power production facilities, the efficiency standards contained in the proposed rule have been eliminated, and the permitted level of oil, natural gas and coal use for startup, testing, flame stabilization, and operation during outages of the primary energy supply system has been increased and the form of that requirement has been simplified. For qualifying cogeneration facilities, efficiency standards still must be met by certain new facilities using oil or gas. In addition, certain operating standards have been adopted for purposes of assuring that a qualifying cogenerator is a *bona fide* cogenerator.

III. Section-by-Section Analysis

§ 292.201 *Scope*

Section 292.201 describes the scope of Subpart B of the Commission's rules. Subpart B provides the criteria for and manner of qualification of small power production and cogeneration facilities.

§ 292.202 *Definitions*

This section contains definitions applicable to this subpart of the Commission's rules.

Paragraph (a) defines "biomass" as any organic material not derived from fossil fuels. The proposed rule defined "biomass" as plant materials which are obtained from cultivation, or harvested from naturally occurring vegetation without significant depletion of the resource. Commenters recommended that the Commission expand the definition to include any organic material not derived from fossil fuels. The commenters stated that most studies dealing with energy recovery from organic material other than fossil fuels have included municipal (and most industrial) solid waste within the more general category of biomass.

The Commission agrees with the commenters who urged the Commission to expand the scope of this definition. The Commission observes that applying a narrow definition of biomass might hinder development of small power production facilities between 30 megawatts and 80 megawatts in capacity. Use of a definition of biomass which includes by-products of the manufacturing, harvesting, and growing of agricultural products, including wood, will enable a greater number of small power producers between 30 and 80 megawatts to take advantage of the exemption from State law and regulation regarding rates and financial organization of electric utilities and from the Public Utility Holding Company Act, as provided in subpart F of this part of the Commission's rules.

One commenter questioned whether the Commission meant to include peat within the definition of biomass. The Commission wishes to clarify this point by stating that peat is included in the definition of biomass for purposes of this subpart.

Paragraph (b) defines "waste" as any by-product materials other than biomass. In most instances, waste is a by-product of fossil fuels. Examples of waste include petroleum coke, refinery gas, and plastics.

Paragraph (c) defines "cogeneration facility" as equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy.

Several commenters requested clarification of the applicability of the Commission's rules to cogeneration in the residential sector. The issue arises because of the absence of any explicit mention of residential energy use in the statutory language. The Commission's definition of cogeneration facility tracks the statutory language in that residential use is not specifically identified.

The Commission intends that residential sector cogeneration be included. The Commission believes that the phrase "heating, or cooling purposes" applies to any industrial, commercial, or residential heating or cooling purpose. The Commission has not found anything in the legislative history of PURPA which suggests that the terms "industrial" and "commercial" were intended to modify "heating, or cooling". Separate mention of "residential" use is unnecessary because heating and cooling adequately encompass the residential use of thermal energy. In the industrial sector, thermal energy in the form of process steam is used as an input to many industrial processes. The separate identification of industrial and heating uses is necessary since not all industrial uses of thermal energy are for heating or cooling purposes. In addition, in many instances, commercial heating purposes include heating of residential apartment buildings, so that the exclusion of residential heating and cooling from this program would be difficult to accomplish even if such purpose were within the realm of statutory construction.

Sequential Use

Several commenters recommended that the Commission define cogeneration as the "combined" or "joint" production of heat and power. However, the terms "combined" or "joint" production of heat and power do not fully describe the cogeneration process. The final rules contain an explicit requirement for the sequential use of energy in cogeneration facilities. This means that rejected heat from a power production or heating process is used in another power production or heating process. It is precisely this "cascading" use of energy in sequential processes that gives rise to the energy conserving characteristic of cogeneration.

By adding the phrase "through the sequential use of energy" to the definition of cogeneration facility, the Commission makes explicit what was intended in the proposed rule. The discussions in the proposed rule relating to topping and bottoming-cycle cogeneration and the efficiency standards were expressed in the context of sequential use. Many commenters apparently recognized this fact and, in their discussions of alternative efficiency standards, compared hypothetical cogeneration systems to reference cases of noncogeneration, separate production of heat and power. Additionally the explanation of supplementary firing in the proposed rules implied that energy inputs other than supplementary firing would have to flow through both a thermal and a power production process. The explicit mention of sequential use is therefore not a new requirement; it is a clarification of intent.

Several comments filed in this rulemaking in response to the Commission's November 9, 1979 interim

[1] raised questions about how the sequential use concept would apply in certain situations. One commenter noted that many industries commonly route steam directly from their boilers to processes without expansion in a turbine. This practice is simply the raising of process steam; it is not cogeneration. The fact that some other steam from the same boiler is routed to cogeneration equipment does not mean that all steam from the boiler is used for cogeneration. The coincident raising of process steam relates to the cogeneration rules in two ways. First, any energy expended in raising such steam should not be entered into any efficiency calculations. Secondly, natural gas used for raising process steam is not rendered exempt from incremental pricing solely because the boiler may also supply steam for cogeneration.

A commenter also questioned the applicability of the sequential use test to a combustion turbine coupled with a waste heat recovery boiler. The commenter noted that the boiler could not capture all of the heat in the turbine exhaust and thus not all of the turbine's power could be said to be sequential. The Commission does not adopt this interpretation. The high efficiency of combustion turbine/waste heat recovery boilers derives from the fact that a substantial quantity of waste heat is recovered. The Commission does not require that all heat be recovered. Strictly speaking, some of the available thermal energy in a steam turbine cogeneration system is lost (due to pressure drop in piping along with convective and radiative heat losses) before the steam is delivered to a useful process. As long as any applicable efficiency and operating standards are met, the Commission is not concerned with energy losses within the system.

A final issue concerning the definition of a cogeneration facility involves combined-cycle electric generation plants. Such plants burn gaseous or liquid fuels in a combustion turbine and use the turbine exhaust to raise steam. The steam is directed through a fully condensing steam turbine. Only electricity is produced, albeit through the sequential use of energy. The Commission is of the opinion that combined-cycle electric generation plants are not cogeneration facilities, since only one form of energy is produced.

[1] Interim Rule for Qualification of Gas-fired Cogeneration Facilities for Purposes of the Incremental Pricing Program, 44 FR 65744 (Nov. 15, 1979).

In paragraph (d), the Commission has added the definition of "topping-cycle cogeneration facility" which is a cogeneration facility in which the energy input to the facility is first used to produce power, and the reject heat from power production is then used to provide useful heat.

Paragraph (e) has been added to define a "bottoming-cycle cogeneration facility" as a cogeneration facility in which the energy input to the system is first applied to a useful heating process, and the residual heat emerging from the process is then used for power production.

The Commission has added paragraph (f), which defines "supplementary firing" as an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility.

The distinguishing characteristic of supplementary firing as defined here is that none of the energy is used sequentially. In topping cycles, supplementary firing is commonly practiced by introducing natural gas or oil into the hot exhaust of a combustion turbine. The turbine exhaust will typically have sufficient oxygen to support combustion of the added fuel. The resulting heat can either be used directly in a high-temperature direct heat application or used to raise process steam. Supplementary firing is also possible in steam turbine cogeneration facilities, through reheat of steam which exists from a turbine. In all cases, the added energy is not used to produce power as well as useful thermal energy.

In a bottoming-cycle cogeneration facility, [illegible] firing can be used to increase the output of the power production equipment by firing additional fuel in the [illegible] exhaust [illegible] used sequentially for both power production and a thermal process.

The Commission recognizes that there will be questions as to the application of the standards of this subpart to complex facilities which may contain combinations of topping and bottoming-cycle cogeneration equipment. The optional procedure for qualification under § 292.207 is available specifically to help any cogenerator who wishes clarification as to whether his facility would qualify.

Paragraph (g) adds the definition of "useful power output" of a cogeneration facility as the electrical or mechanical energy made available for use, exclusive of any such energy used in the power production process. Although electric power output is required of a qualifying facility, any additional mechanical power may be taken into account in determining "useful power output".

Paragraph (h) has been added to define "useful thermal energy output" of a topping-cycle cogeneration facility as the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application.

The proposed rules contained a definition of the "useful energy output of a thermal process." The term was intended to reflect the heat actually used in a thermal process rather than heat made available for use. The proposed term found application in proposed efficiency standards for both topping and bottoming cycles. Only a few commenters mentioned the proposed term, but they did raise serious questions about the feasibility (and desirability) of performing the necessary calculations. It was argued that computation of the "useful energy output of a thermal process" in accordance with the proposed definition would be difficult and would yield unintended results—particularly in the case of bottoming cycles.

The Commission notes that in its final rules the [illegible] of bottoming-cycle facilities [illegible] only with respect to [illegible] firing. No evaluation of [illegible] is now required for the thermal process of a bottoming cycle.

For new topping-cycle facilities burning natural gas or oil, however, the degree to which heat is recovered and put to use remains a concern. The final rules contain a definition of "useful thermal energy output" which eliminates the problems of the proposed terminology. Under the new definition, in the case of industrial or commercial process use of thermal energy, the thermal energy made available for use in the process may be considered useful thermal energy output of a cogeneration facility. Thus an industrial process which uses steam or heat need not be analyzed for the purpose of determining what fraction of the energy delivered to the process is actually put to use.

In the case of space heating and cooling, water heating, and related heating and cooling applications, a cogeneration facility's useful thermal energy output is the energy actually used in the application. For example, a cogeneration facility may consist of a combustion turbine with exhaust heat recovery used for space heating. In this example, the useful thermal energy output would be the heat recovered from the exhaust and actually used for space heating, not all of the heat available in the exhaust.

Paragraph (i) defines "total energy output" of a topping-cycle cogeneration facility as the sum of the useful power output and useful thermal energy output.

Paragraph (j) defines the term "total energy input" as the total energy of all forms supplied from external sources, other than supplementary firing, to the facility.

The total energy input to a cogeneration facility includes all fuels and renewable resources used in the facility. Energy taken from one part of the facility and used in another part of the cogeneration process does not meet the test of being supplied from an external source. For example, boiler feedwater pumping, heating, and deaerating are energy uses internal to the cogeneration facility and are not to be considered as either energy inputs or energy outputs.

The Commission has added the definition of natural gas in paragraph (k) as it is defined in the Natural Gas Act, which is natural gas unmixed, or any mixture of natural gas and artificial gas. This is intended to cover natural gas supplied by any natural gas company as defined in the Natural Gas Act or any distribution company selling natural gas. As a result, the efficiency standards under § 292.205 only apply with respect to the natural gas so defined and do not apply with regard to any synthetic gas which is unmixed in the pipeline, or mixed by the end-user, such as coke oven gas, blast furnace gas, or gas derived from coal or shale oil.

The definition of "oil" has been added in paragraph (l) to mean crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products. This definition does not include refinery-off gas, petroleum coke, or other waste products of the refinery process.

Finally, the Commission has provided in paragraph (m) that, for purposes of this subpart, in the case of energy in the form of natural gas or oil, energy input is to be measured by the lower heating value of such fuel.

In the proposed rules, energy inputs in the form of fossil fuels were to be evaluated in terms of the lower heating value of such fuels. A few commenters took issue with the use of lower heating values and recommended that higher heating values be specified in the final rule.

Lower heating values were specified in the proposed rules in recognition of the fact that practical cogeneration systems cannot recover and use the latent heat of water vapor formed in the combustion of hydrocarbon fuels. By specifying that energy input to a facility excludes energy that could not be recovered, the Commission hoped that the proposed energy efficiency standards would be easier to understand and apply. The Commission also wished to a apply a standard that would be more uniform in the treatment of natural gas and oil. Owing to the difference in chemical composition, more latent, unrecoverable heat is lost in the combustion of gas as compared to oil. The Commission did not wish indirectly to make qualification more difficult for natural gas-fired cogeneration facilities by requiring a higher level of sensible heat recovery.

The commenters opposing the use of lower heating values generally argued that customary practice is to use higher heating values. The Commission does not find this argument compelling. Both heating values of fuels can easily be found in handbooks. Moreover, if a cogenerator wishes to use the higher heating value of fossil fuel inputs for computing efficiency, the Commission has no objection. Any facility qualifying with efficiency so computed would certainly qualify under the more lenient rules set forth. As a result, the Commission does not believe it appropriate to change this aspect of the proposed rule in this final rule.

§ 292.203 General requirements for qualification.

The proposed rule provided that any person seeking qualifying status for a facility had to initiate discussions with the utility with which it wishes to interconnect and file an application with this Commission. The proposed rule set forth the contents of an application for certification which included technical information describing the facility, a summary of discussions required to be held between the applicant and the affected electric utility, and a description of the equity ownership of the facility. In addition, a small power producer was required to provide information about its primary energy source and its location. A cogenerator was required to submit information describing the energy input and output of the facility in both the heat engines and thermal processes.

The majority of comments favored eliminating the filing requirement either for all qualifying facilities or for specific classes of qualifying facilities. Several commenters suggested that the complexity, delays, and uncertainties created by a case-by-case qualification procedure would act as significant economic disincentive to owners of smaller facilities. Other commenters recommended exempting smaller facilities, such as facilities with an aggregate electrical capacity of up to 250 or 800 kW, from formal filing requirements. A utility [8] stated that the application procedure does not serve any party or the public's interest. This commenter preferred to see regulations on an "exception" basis where the utility, State regulatory authority or other interested party could object to the granting of qualifying status.

The Commission finds substantial merit in these comments. The Commission believes the initiation of purchase and sale arrangements, pursuant to Subpart C of this part of the Commission's rules, will necessitate the flow of information between potential qualifying facilities and affected electric utilities. The Commission therefore notes that the requirements contained in the proposed rule both for discussions between a potential qualifying facility and the utility with which it wishes to interconnect and for the filing of substantial information with this Commission are not necessary.

For example, one commenter [9] suggested modifying the pre-application negotiation requirements to require that an applicant initiate discussions with the utility prior to filing if the cogenerator or small power producer is intending to negotiate an individual contract. However, if the applicant merely wants to establish his eligibility for an already-published rate schedule for qualifying facilities, this commenter claims that there would be nothing to negotiate, and thus no reason to require that discussions be held. It was asserted that notification to the utility at the time of application would suffice in such cases. The Commission believes that this is what would and should happen without any requirement from the Commission. In addition, the Commission believes that, as a practical matter, an electric utility, which is notified by a qualifying facility that it wishes to interconnect with the utility in order that the utility may purchase the power produced by the facility, will need to know the nature of the qualifying facility's expected purchases and sales so as to be able to arrange safe and reliable interconnected operation at appropriate rates.

As a result, the requirement for case-by-case qualification has been eliminated. Section 292.207(a) of this rule provides that any small power production or cogeneration facility which meets the requirements for qualification set forth in that section is a qualifying facility.

However, the Commission has provided an optional procedure in § 292.207(b) of this rule whereby an

[8] Pacific Gas and Electric Company.

[9] U.S. Department of Energy.

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application for Commission certification of qualifying status may be filed at the discretion of the owner or operator of the facility.

There was some confusion in the comments as to who actually qualifies under this program. The facility qualifies and that entitles the owners and operators of the facility to receive the benefits of qualification under this part. The benefits of qualification under this part, however, are only with respect to the qualifying facility. For example, the owner or operator of a qualifying cogeneration facility is entitled to require the utility to sell power to his qualifying facility in compliance with the terms of § 292.305 as implemented by the State regulatory authority. The owner or operator has no entitlement to require such rate treatment for the utility's sales to other facilities he may own or operate which are not qualifying facilities. Similarly, his sales to the utility will be exempt under Subpart F of this part from certain Federal and State regulation only to the extent the sales are from a qualifying facility.

§ 292.203(a) Small power production facilities.

Section 292.203(a) provides that a small power production facility is a qualifying facility if it meets three criteria.

The first requirement is that the power production capacity of the facility, together with the capacity of any other facilities that use the same energy resource and are owned by the same person and are located at the same site, may not exceed 80 megawatts. The method by which the capacity is determined is described in this preamble under § 292.204.

The second requirement is that the primary [illegible] resources, or any [illegible] This means that more than 50 percent of the total energy input must be in these categories. In addition, the aggregate use of oil, natural gas, and coal by the facility may not exceed 25 percent of its total energy input during any calendar year. These fuel use criteria are discussed further in § 292.204(b).

Thirdly, a small power production facility will not be eligible for qualifying status if more than 50 percent of the equity interest in the facility is held by an electric utility or public utility holding company or any person owned by either. Section 292.206 describes this ownership test in greater detail.

One commenter raised the question as to whether a facility is included within the definition of a small power production facility in the statute, and hence the Commission's regulations, if the facility is only part of the process of producing electric energy; namely, raising steam. This commenter produces steam using municipal solid waste, which steam is then sold through an adjoining wall to an electric utility to run through a turbine and produce electricity. In a sense, this facility indirectly produces electric energy. It is unclear to the Commission how this steam-raising facility would benefit from the regulations under section 210. It is not selling electric energy to the utility; it may be buying some electric energy from the utility; and it seems unlikely that it would be subject to electric utility regulation. Therefore, the Commission does not, at this time, see the need to allow qualification for these kinds of facilities, without judging as to whether the Commission could allow such qualification under the statute.

§ 292.203(b) Cogeneration facilities.

Section 292.203(b) provides that, with the exception of new diesel cogeneration facilities, a cogeneration facility may be a qualifying facility if it satisfies two requirements. First, it must meet the same ownership test as that required for a small power production facility. Secondly, it must meet any operating and efficiency standards described in § 292.205(a) and (b).

In addition, cogeneration facilities which wish to qualify for the incremental pricing exemption permitted under Title II of the Natural Gas Policy Act of 1978 (NGPA) and Part 282 of the Commission's rules must meet the requirements stated in § 292.205(c).

Section 201 of PURPA provides that "a 'qualifying cogeneration facility' means a facility which—(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe * * *". Several comments contended that the statutory language *requires* the Commission to establish standards relating to all of the mentioned criteria. The legislative history of this section indicates that the phrase "as the Commission may * * *" was added in conference; it did not appear in either the House or Senate bill.[19] The plain meaning of the provision, as adopted by the Conferees, is that a qualifying cogeneration facility must meet requirements that the Commission, in its discretion, establishes. These may, but need not, include requirements respecting minimum size, fuel use, and fuel efficiency.

The Commission received numerous comments from utilities recommending that oil- and natural gas-fired cogeneration facilities not be considered eligible for qualifying status. These commenters generally argued that encouragement of such facilities would be contrary to Congressional intent and national energy policy. Comments were also received expressing strong support for the policy presented in the proposed rule, which did not impose a restriction on oil and natural gas use.

The Commission believes the policy expressed in the proposed rules is consistent with Congressional intent and national energy policy. Had Congress not intended that the benefits of qualifying status be extended to oil- and natural gas-fired cogeneration facilities, the statute or Joint Explanatory Statement of the Committee on Conference (Conference Report) would have contained a restriction on fuel use similar to that which is provided for small power producers. The Congress knew that cogeneration facilities typically use natural gas and oil. In addition, the Natural Gas Policy Act of 1978 contains an express exemption from the incremental pricing program for natural gas used in qualifying cogeneration facilities, which further indicates Congressional recognition that cogeneration facilities use natural gas.

Thirdly, the Congress enacted the Powerplant and Industrial Fuel Use Act (PIFUA) at the same time as PURPA. PIFUA provides authority to the Secretary of Energy to restrict the use of oil and gas in cogeneration facilities. Therefore, the Commission does not believe it necessary or appropriate to require an additional layer of fuel use regulation on technologies which the Commission is charged with encouraging and for which another agency has authority to restrict fuel use.

The Commission also notes that the findings in section 2 of PURPA specifically require "a program providing for * * * increased efficiency in the use of facilities and resources * * *". To the extent that oil and natural gas-fired cogeneration facilities provide for more efficient use of these resources, the Commission believes that the benefits of qualifying status should be extended to them.

Some of the comments stated that permitting qualifying cogeneration facilities to use oil, especially in diesel engines, will use up available air quality increments, thereby preventing the conversion of large utility oil-fired

[19] See Comparative Print to H.R. 4018, Public Utility Regulatory Policies Act, 72, 95th Cong., 2d Sess. (1978).

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oilers to coal. As noted above, the Commission believes it is not proper to address this fuel use issue within the context of this program. However, the Commission has not made a final determination regarding the environmental effects of new diesel cogeneration facilities, and is therefore including in these regulations an interim exclusion from qualification of this technology until work on an environmental impact statement has been completed.

292.203(c) Interim exclusion.

Section 292.203(c) provides that, pending further Commission action, any cogeneration facility which is a new diesel cogeneration facility may not be a qualifying facility. A new diesel cogeneration facility is described as a cogeneration facility which derives its useful power output from a diesel engine, the installation of which began on or after March 13, 1980.

Through the issuance of these rules and the rules implementing section 210 of PURPA, the Commission intends to carry out the legislative mandate to provide encouragement to the energy technologies included within the program. The Commission is required under the National Environmental Policy Act of 1969 (NEPA) to take the environmental effects of this encouragement into account. The Commission has circulated and received public comment on a preliminary Environmental Assessment (EA) of these rules which was issued on October 19, 1979.

(See Appendix I)

Environmental Findings

The identification of the environmental effects associated with a "major Federal action" [11] is not ordinarily a difficult task. These effects typically are those associated with the construction and operation of a particular project in which the Federal government is playing a major role, such as by funding or licensing. In contrast, these rules and the rules implementing section 210 of PURPA do not authorize or fund any particular projects: moreover, they do not authorize or forbid the use of certain fuels. Instead, they provide certain economic incentives to, and remove other disincentives (*i.e.*, assurance of a market for electrical production and exemption from utility regulation) from certain classes of technologies. It is important to note that, even without these rules, these technologies have been, and would continue to be, utilized. The environmental effects associated with this "base-case" level of development cannot be ascribed to these rules. Instead, the proper way to isolate and identify the effects of these rules is to predict the "base-case" (no PURPA) level of development, and determine the environmental effects of that level of development, and compare it to the effects of the projected development with these rules in place. Under this approach, any changes from the base-case review are properly classified as effects of these rules.

The first step used in determining the environmental effects of these rules was to compare, by region, representative electric utility rates with the cost of generating electricity by use of a qualifying facility. This comparison established which technologies would be economically viable. Next, the costs of generating electricity by the facility were compared to an estimate of utilities' avoided costs on a regional basis. If, by receiving the avoided cost for its output, a facility would operate economically, it was considered to have been "PURPA-induced." Avoided cost is the maximum price inducement under this program.

For technologies which would, as a result of PURPA, be economic, regional levels of market penetration were established on the basis of site availability and manufacturing capability. Finally, the environmental effects associated with the predicted level of development were calculated.

The Environmental Assessment accompanying this order describes the environmental effects associated with all of the types of technologies encompassed in section 201 of PURPA. The quantitative effects associated with the predicted market penetration of each technology were then estimated.

The Environmental Assessment includes an extensive market-penetration analysis of each technology eligible for qualification under the Commission's proposed rules and of the aggregate of all of these technologies. Since the proposed rules took the broadest view of which technologies would be eligible for qualification, the analysis covers all technologies, which, under the statute, may be eligible for qualification. On the basis of this analysis, the Commission has estimated the amount of capacity expected to be induced on a regional and national basis through January 1, 1995, assuming the broadest implementation of this program.

This analysis shows that this program may result in the construction of 12,000 MW of new capacity by qualifying facilities by 1995, and the reduction in utility construction of 10,000 MW of new capacity. It also indicates a possible fuel savings in 1995 of 40,000 bbl/day of oil, 40,000 bbl/day equivalent of natural gas, and 120,000 bbl/day equivalent of coal, as the use of renewable resources increases, and more efficient use is made of both renewable and non-renewable resources.

The Environmental Assessment finds that there will be both adverse and beneficial environmental effects associated with this program. Some of the technologies produce certain air emissions, water effluents, and other environmental effects. However, material and thermal by-products of industrial, commercial, agricultural and other activities that would otherwise contribute to environmental degradation will be consumed or otherwise utilized in the production of useful energy under this program.

In addition, the Environmental Assessment indicates that utilities will be able to defer or cancel construction of certain facilities, originally scheduled for construction between 1980–1995. These deferrals or cancellations are expected to include some eleven 500 MW coal-fired steam plants, one 1,000 MW nuclear plant, a number of 75 MW gas turbines, and certain large scale hydropower and combined cycle installations. The environmental impacts associated with the construction and operation of these facilities would be avoided.

Finally, the market-penetration analysis in the Environmental Assessment indicates that the incentives provided by this program will not significantly affect the development of some technologies while they will significantly encourage others. For example, it appears that this program will significantly encourage small hydroelectric power development. Water power project impacts are usually site-specific and localized, with no cumulative impact on a national basis, and few impacts of regional significance. The Commission notes that hydroelectric projects in almost all cases must be licensed by the Commission. License applications are evaluated on a case-by-case basis to determine the significance of the environmental impacts and the need for a site-specific EIS. In addition, impacts of individual projects on a waterway may be cumulative, and the Commission reviews each project in relation to others on the waterway under the "comprehensive development" standard of section 10(a) of the Federal Power Act. Therefore, even though only the

[11] Section 102(2)(c) of the National Environmental Policy Act of 1969, Pub. L. 91-190

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general nature of the kinds of environmental effects can be evaluated in this programmatic environmental assessment of national scope. requirements of the National Environmental Policy Act of 1969 (NEPA) will be met as each application is filed.

For certain other technologies, the level of environmental effects associated with the PURPA-induced market penetration of these technologies will not approach a significant level in the near term.[12] The Commission will monitor the PURPA-induced market penetration of these technologies carefully.

In the public comments, evidence was presented indicating that the environmental consequences of qualifying new diesel cogeneration may be significant in the near term, in certain geographic areas, even with a moderate level of market penetration. Therefore, the Commission believes that it is appropriate to delay action on qualification of new diesel cogeneration until completion of an EIS. The Commission will circulate a draft EIS within the next month and conclude its analysis within 90 days of circulation.

The Commission acknowledges the difficulties in identifying the levels of the environmental effects associated with the programmatic encouragement and deregulation of various types of technologies as are present under this program. There are, of course, a great number of uncertainties in any such analysis. However, the Commission is required under NEPA to assess these effects to the fullest extent possible.

On the basis of its environmental review, the Commission has made the following findings in its Environmental Assessment:

—The program, taken as a whole, will not have a significant impact on the quality of the human environment within the meaning of section 102 of NEPA. The Commission also has noted certain beneficial environmental impacts that may result from this program.

—Where the expected market penetration of technologies which could qualify under this program is not expected to cause any significant environmental effects in the near term, the Commission will allow qualification of these technologies without delay.

—Where a technology is expected to cause significant environmental effects in the near term, an EIS covering the technology will be prepared and considered before the Commission acts on qualification.

—The Commission is establishing a monitoring program to alert the Commission to the likelihood or extent of market penetration by technologies which qualify under this program. This is designed to produce information that may be relevant to taking appropriate environmental protection action in the future before the program reaches a stage of investment or commitment to implementation likely to determine subsequent development or restrict later alternatives.

[12] See Figures 3 through 7 in the Environmental Assessment.

§ 292.204(a) Criteria for qualifying small power production facilities.

Section 292.204 sets forth qualification requirements for small power production facilities. Paragraph (a) implements the statutory requirement that the power production capacity of a small power production facility not exceed 80 megawatts at any site. In order to implement this limitation, the proposed rules provided that the capacity of all facilities which use the same energy resource, are owned by the same person, and are located within one mile of each other be added together. Commenters recommended eliminating the site criterion because the important criterion is not siting but that facilities use alternate energy resources. The Commission recognizes the difficulty in prescribing site criteria for purposes of calculation of the size of the facility. However, the Commission is obligated under the statute to limit qualifying status for small power production facilities to those facilities which have "a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts."[13]

In subparagraph (2)(i), the Commission defines "facilities located at the same site" as facilities located within one mile of the facility for which qualification is sought. Hydroelectric facilities (within this distance) are considered to be located at the same site only if the facilities use water from the same impoundment for power generation. The Commission views this additional provision for hydroelectric facilities as necessary because use of the one-mile rule alone might discourage the development of facilities on separate waterways which are within one mile of each other or of closely-spaced impoundments on an individual stream.

The Commission also notes that in some instances hydropower resources may be developed without an impoundment. In this case, the one-mile rule would be the only factor in determining the size of a facility.

In response to comments, the Commission has added subparagraph (2)(ii) which requires, for purposes of determining the distance between facilities, that any measurement shall be made from the electrical generating equipment of a facility. The comments noted that some facilities may include equipment for gathering energy to be used in the facility which may extend up to a number of miles from the generating facility. The Commission believes that the one-mile limit should be measured from the generating facilities.

[13] Section 3(17)(A)(i) of the Federal Power Act.

The proposed rule enabled an applicant to rebut the presumption that facilities located within one mile of the facility for which qualification is sought, using the same energy resource and owned by the same person, should be considered to be located at the same site. The Commission believes that the requirement to rebut the presumption was burdensome and confusing. Therefore, the final rule has been revised to enable a small power producer or cogenerator to apply to the Commission for a waiver for good cause.

The proposed rule also contained a minimum size limit of 10 kW for qualification of small power production facilities. This proposal was based on the Commission's view that facilities smaller than 10 kW were unlikely to be economically viable, and that the administrative burden of arranging interconnected operation with them would be greater than the benefits they would provide to the system at this time. This proposal attracted considerable comment, both at the public hearings and in written recommendations. The majority of the comments objected to the minimum size provision and indicated that a number of facilities smaller than 10 kW are being built and that some units are presently commercially available. Commenters also stated that these facilities can be equipped with electrical protection equipment which permits safe interconnected operation.

Several utilities, on the other hand, suggested raising the minimum size limit, arguing that small facilities are not cost-effective. The Commission notes that the rules implementing section 210 of PURPA (Subpart C of this part) require that standard rates be provided for facilities up to 100 kW. Those rules together with the self-qualification provisions of these rules greatly ease the administrative burdens on all parties. The Commission also notes that the rules implementing section 210 of PURPA require that a qualifying facility is obligated to pay any interconnection costs assessed against it by the State regulatory authority or nonregulated electric utility. Since under these rules the utility is not obligated to incur any additional costs by reason of interconnected operation with these facilities, the minimum size limitation

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has been eliminated to allow individual decisions to govern whether or not to install these very small facilities.

§ 292.204(b) Fuel Use.

Paragraph (b) sets forth fuel use requirements for qualifying small power production facilities. In the proposed rule, the term "primary energy source" was not defined. Several commenters noted this fact and asked that the final rules specify a definition for the term. Subparagraph (1) provides that the primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 50 ~~percent of the total~~ energy input must be from these sources. The Commission notes that this requirement is not intended to force small power producers to continually monitor the energy input, but rather that reasonable estimates based on sampling methods are sufficient.

Qualifying small power production facilities using biomass as a primary energy source are treated differently than are facilities using other resources for purposes of exemption from the Public Utility Holding Company Act and certain State law and regulation under section 210(e) of PURPA and under § 292.602 of the Commission's regulations. A further concern in determining a facility's primary energy source is the treatment of mixtures of biomass and waste or renewable resources. Therefore, in subparagraph (1), the Commission specifies that any primary energy source which, on the basis of its energy content, is more than 50 percent biomass shall be considered biomass. In other words, a qualifying facility may be considered biomass-fired if, on an estimated annual basis, at least half the energy input, exclusive of fossil fuel use, is biomass.

The Commission expects that this rule will extend the benefits of the biomass exemption provisions to a broad range of facilities. For example, evidence presented in this rulemaking indicated that much more than half of the energy content in municipal solid waste is due to "organic material not derived from fossil fuels," or "biomass" under the Commission's definitions. Thus, a small power production facility fired with municipal solid waste may be considered a biomass facility. The same treatment applies to facilities fired with forest-industry residues, [illegible] or peat.

Another aspect of what constitutes "primary energy source" is a specification of what fuels may be used in addition to the primary energy source for purposes of ignition, startup, testing, flame stabilization and control, and during equipment outages and emergencies.

Section 3(17)(B) of the Federal Power Act, as amended by section 201 of PURPA, provides that:

" 'Primary energy source' means the fuel or fuels used for the generation of electric energy except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy—

"(i) The minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and

"(ii) The minimum amounts of fuel required to alleviate or prevent—

"(I) Unanticipated equipment outages, and

"(II) Emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages."

The proposed rule set forth limits for the allowable use of fossil fuels. Three separate standards were proposed: One for ignition, startup and testing; another for flame stabilization and control; and a third for fuel use during outages of the primary energy supply system. All of the proposed standards were set in terms of barrels of oil per year per megawatt of rated capacity.

The comments filed on this section generally favored less restrictive fossil fuel limitations. Several commenters noted that standards written in terms of barrels of oil were imprecise, since the energy content of a barrel of oil is not constant. Other commenters argued that separate standards for startup, flame stabilization and outages were unnecessarily burdensome. Commenters claimed that some small power production technologies would be severely constrained by one of the standards, while requiring little or no fossil fuel for other purposes. Additionally, to the extent oil and natural gas remain more expensive than other energy sources available to small power producers, there is an economic disincentive to use oil and natural gas. Thus it was argued that a single standard for allowable fossil fuel use would be more equitable and workable when dealing with a number of types of facilities. The Commission has decided to adopt this recommendation.

Many other commenters recommended that the Commission adopt alternative amounts of fossil fuel for use during outages and for other purposes. For the purpose of specifying the minimum amounts of fuel under clauses (i) and (ii) of section 3(17)(B) of the Federal Power Act, the Commission adopts in this rulemaking the standard, recommended by several commenters, that no more than 25 percent of the total energy input during any calendar year may consist of fossil fuels—namely oil, natural gas, and coal.

With this simple rule, a qualifying facility can use up to the allowed quantity of fossil fuel for purposes specified in the statute. No question remains concerning what sort of primary fuel system supply outages are within the scope of the rule. The standard does require every small power producer be able to estimate the energy content of the primary energy source. The Commission recognizes that for some energy sources, municipal solid waste in particular, energy content is not uniform. As has been stated earlier, the Commission believes that reasonable estimates will suffice for purposes of this rule. Finally, it should be noted that the fossil fuel limitation applies only to small power production facilities. Some commenters apparently regarded the limitations as equally applicable to cogeneration facilities. This is not the case.

Another issue raised by the proposed rule was the limitation of renewable resources to water used at existing dams. Commenters urged the Commission to expand the definition of renewable resources to include water used at new hydroelectric facilities. The Commission has reviewed the Conference Report and has determined that the conferees did not intend to restrict the term renewable resources to water used only at existing dams. The Commission believes that such an interpretation conflicts with the conventional use of the term "renewable resources" as including all hydroelectric sources, not just those using existing dams. Therefore, the Commission intends that the term renewable resources applies to water used at existing and new hydroelectric facilities of less than 80 megawatts.

§ 292.205 Criteria for qualifying cogeneration facilities.

§ 292.205(a)(1) Operating standards for topping-cycle cogeneration facilities.

In its Notice of Proposed Rulemaking, the Commission recognized the problem of distinguishing cogeneration facilities which achieve meaningful energy conservation from those which are merely "token" facilities, producing trivial amounts of either useful heat or power. In the proposed rules, the *bona fide* character of a facility was to be determined by minimum amounts of useful heat and power output.

The need for operating standards as a means of identifying *bona fide* cogeneration facilities drew considerable comment. Some comments indicated that this formulation had the

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useful thermal output be greater than 45 percent of the facility's energy consumption, this proposal would ensure that qualifying facilities produce heat and power more efficiently than a 8500 Btu/kWh combined cycle generating station and a 90 percent efficient process steam boiler.

Moreover, this proposal appears to impact the various cogeneration technologies more equitably than the other proposed standards. The other proposals for required overall efficiency, by simply summing heat and power on an equal basis, make qualification relatively easy for steam turbine systems which produce little electricity. Cogeneration systems which produce high ratios of electricity to heat would be penalized with difficult heat recovery requirements. Yet the systems with high electricity to heat ratios have the highest "second law" energy efficiencies. Futhermore, a standard which is relatively lenient towards oil- and natural gas-fired steam cogeneration would encourage boiler fuel use of distillate oil and natural gas.

The proposal of another commenter, although considered in detail, would impact different cogeneratio technologies differently and would not give assurance of energy conservation.[30]

In light of the foregoing considerations, the Commission has decided to adopt a standard in paragraph (a)(2)(i) similar to that proposed by the Massachusetts Office of Energy Resources as its standard for efficiency of new oil- and natural gas-fired topping-cycle cogeneration systems. This standard requires that for any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil and the installation of which began on or after March 13, 1980,[31] the useful power output plus one-half the useful thermal energy output of the facility must be, during any calendar year, no less than 42.5 percent of the energy input of natural gas and oil to the facility. The Commission adopted a value of 42.5 percent, rather than the 45 percent recommended by the Massachusetts comments because, in the Commission's view, the 45 percent requirement appears overly restrictive for steam turbine cogeneration facilities in that very high boiler efficiencies would have been required. However, if the useful thermal energy output of any such facility is less than 15 percent of its total energy output, the useful power output plus one-half the useful thermal energy output of the facility must be no less than 45 percent of the total energy input of natural gas and oil to the facility.

Existing Versus New Cogeneration Facilities

Although the Commission has found a compelling reason to impose efficiency standards on new oil and gas burning cogeneration facilities, the situation with respect to existing facilities is different. Existing facilities are those for which the installation of the cogeneration equipment began before the Commission actions encouraging cogeneration under this program were finalized. Presumably, such facilities would continue to be installed or operated using whatever fuels they are equipped to burn, with or without the incentives of PURPA.

Allowing existing facilities to qualify will provide for more flexible operation of the facilities. Optimum efficiency of a cogeneration facility may be more easily approached through interconnected operation with an electric utility. Because of the foregoing considerations, denial of qualifying status would serve no useful purpose.

Existing cogeneration facilities burning oil or natural gas were, in large measure, installed in an environment of lower fuel prices. Such facilities may not be able to meet the higher standards now reasonable for use of scarce fuels. Yet failure to meet standards intended for new facilities should not preclude entitlement to sell power to the utility and to receive the other rate benefits, as provided under Subpart C of these rules. In addition, the denial of exemption from regulation as an electric utility may discourage cogeneration at existing facilities.

The Commission has decided against imposing any efficiency standards on existing facilities, regardless of energy source. There is no assurance that imposing standards would result in fuel savings. The opposite result is more likely, if operating cogeneration facilities are denied the benefits of interconnected operation with an electric utility. Therefore, for any cogeneration facility, the installation of which began before the date the Commission's final rules in this docket were issued, March 13, 1980, no efficiency standards are required for qualification, regardless of energy source or whether it is a topping or bottoming-cycle facility.

Efficiency To Be Based Upon Projected Annual Operation

Several commenters raised the issue of whether efficiency calculations should be based on rated performance characteristics or on expected performance over a period of time. Only half of the commenters that mentioned the issue took a position in favor of one means of computation or another. The balance of the commenters merely asked for clarification.

The Commission is persuaded that the efficiency of a cogeneration facility operating at peak production of power and heat may not necessarily correlate with the efficiency which can be practically realized. A cogeneration facility which serves a highly variable heating load may seldom be operated at peak efficiency. The efficiency standards required for new oil or natural gas cogeneration facilities are intended to assure efficient use of these premium fuels. Use of optimum or design basis circumstances for determining efficiency would not satisfy the Commission's concern. A computation based upon projected or estimated annual operations will more closely reflect the facility's actual energy conservation potential.

The Commission realizes that estimates will be required in order to determine the efficiency of a facility not yet constructed. The Commission believes, however, that such estimates would routinely be performed prior to any decision to invest in cogeneration equipment. No significant burden is therefore expected in determining a cogeneration facility's qualifying status.

Why the Efficiency Standard Based on "Effective Heat Rates" Was Not Adopted

Evaluating the performance of a cogeneration facility in terms of the quantity of additional fuel used per kilowatt hour of electricity generated, above that needed for heating purposes alone, results in a standard known as

[30] The efficiency standard proposed by this commenter, the American Paper Institute, differed from all others fundamentally in that an effective heat rate test was required. A qualifying cogeneration facility was defined as:

A cogeneration facility that for the electric energy produced incrementally to steam or useful energy production

1. Uses less that 9,000 BTU of additional fuel per kilowatt hour and

2. Produces more electric energy than it consumes

And that at least twenty-five percent of the steam, or useful energy, available is applied on an annual basis in industrial, commercial, heating or cooling uses.

[31] The preamble discusses new versus existing facilities. This is expressed in the regulations as "facilities, the installation of which began on or after March 13, 1980," or before that date. The Commission views the beginning of installation as the beginning of physical modification of the site or of pre-existing facilities. Of course, any sharp line will create its own inequities and raise its own questions. The waiver provision of § 292.205(d) is available to redress those inequities, and the optional procedure for qualification under § 292.207(b) is available to answer those questions.

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effect of imposing energy efficiency requirements which are not appropriate for some technologies. Commenters stated that a much simpler test than the proposed standards would be adequate for the task. Two commenters suggested a simple test regarding the portion of energy developed in the form of useful heat or steam. One potential qualifying facility [14] suggested that:

> for geothermal energy cogeneration facilities, the energy utilization by the non-electric processes must average on an annual basis at least 5 percent of the energy consumption of the heat engine.

Another commenter suggested "a minimum of 10% of the total steam generation must be used as steam send-out." [15]

Generally, commenters did not oppose a requirement for distinguishing a *bona fide* cogeneration facility from essentially single purpose facilities, even while taking exception to the form and substance of the proposed efficiency standards. One commenter [16] stated:

> A significant portion of the steam, heat or energy available from the cogeneration unit should be used in an industrial, commercial, heating or cooling applications. The concept of an operator of a large thermal generating station applying condensing techniques bleeding a tiny side stream out to heat a tool shed so that cogeneration could be claimed should be prohibited.

The Department of Energy [17] recommended the inclusion of a requirement that some minimal fractions of useful heat and power be produced. Consequently, the Commission has decided that a simple means of identifying *bona fide* cogeneration facilities is appropriate. The *bona fide* test has been modified to specify only that a minimum proportion of the useful energy output be useful thermal energy output without regard to the energy input. The standard requires that at least 5 percent of a qualifying cogeneration facility's total energy output be in the form of useful thermal energy output. Compliance with this standard is to be based on estimated annual energy output.

Further, this basic *bona fide* test is applicable only to topping-cycle facilities. "Tokenism" is of concern for bottoming-cycle facilities chiefly with regard to the opportunity for qualifying facilities to obtain exemption from incremental pricing under the Natural Gas Policy Act. Natural gas used by bottoming-cycle facilities (other than in supplementary firing), will, as a general matter, be exempt from incremental pricing only to the extent that reject heat is utilized in power production. In view of these provisions, no separate *bona fide* test is necessary.

§ 292.205(a)(2)(i) *Efficiency standards for topping-cycle facilities.*

The proposed rules set forth efficiency standards for oil- and gas-fired topping-cycle cogeneration facilities. The efficiency standards were composed of three separate criteria. The first criterion required, in effect, that no less than 20 percent of the energy input to the facility be converted to mechanical or electrical power. The second criterion specified that 45 percent of the heat rejected from the heat engine (a term used in the proposed rule to describe the power production process) be put to use in a thermal process. The final criterion required at least 60 percent of the energy input to the facility be used either as power or useful heat.

Comments on the proposed efficiency standards criticized both their form and substance. Many commenters stated that the 20 percent efficiency criterion for heat engines was overly restrictive. These commenters pointed out that most steam turbines would not be able to meet the standard with conventional steam inlet and exhaust pressures. Many such steam turbine cogeneration systems would represent energy efficient systems when compared to the standard practice of separate steam and electricity production.

Fewer comments were directed toward the efficiency tests concerning heat recovery and overall efficiency. The comments that were made, however, indicated a need for revision. One commenter indicated that the heat recovery standard would exclude diesel-powered cogeneration facilities even though many such facilities would be highly energy efficient. Comments on the overall efficiency standards were mixed. One commenter suggested that the standard was too lenient. Another commenter recommended that the proposed 60 percent test be reduced to 50 percent, although this commenter appeared to be principally concerned with the application of efficiency standards to the use of renewable resources and not to the use of scarce fuels.

Five commenters addressed the question of efficiency standards for oil- and natural gas-fired cogeneration in a comprehensive manner by proposing a complete set of alternative standards. Four of these five commenters advanced proposals based on energy balance criteria, similar in theory to the proposed standards. A proposal by the New York State Energy Office closely resembled the proposed rule. Under this plan, individual tests for heat engine efficiency, heat recovery, and overall efficiency would still be required. The overall efficiency test would remain at 60 percent, but the heat engine and heat recovery tests would be reduced to 10 percent. This was the only comment in favor of maintaining separate efficiency standards for power production and heat recovery. The criticism of that scheme has caused the Commission to adopt an alternative efficiency standard which better takes into account the variety of technologies which qualify under this rule. The essential issue concerns the proper level of the overall efficiency standard which should be applied in individual cases.

Three commenters proposed efficiency standards relating solely to overall efficiency. A utility [18] recommended a single standard of 50 percent overall efficiency, which was the most lenient standard suggested. This proposal, furthermore, would be related to design efficiency and not actual or estimated operating efficiency. Another commenter [19] recommended a single standard of 65 percent overall efficiency. This standard would be slightly stricter than the first proposal discussed for all facilities except those producing predominantly either electricity or heat. Finally, the Commonwealth of Massachusetts Office of Energy Resources proposed a standard which would weigh thermal energy with only half the value of electricity.

The latter two comments are both supported by well-reasoned examples of cogeneration engineering practice. The Massachusetts proposal is relatively more stringent for facilities producing more heat than electricity, and more lenient for facilities producing much of their output as electricity. The basis for this proposal is a comparison of cogeneration systems based on steam turbine, combustion turbine, and diesel engine prime movers with oil-burning non-cogeneration technology. Essentially, it is argued that any cogeneration facility meeting the proposed efficiency standard will be more efficient than any combination of separately generated electricity and steam using efficient, state-of-the-art technology. By requiring that the sum of useful power output and one-half the

[14] Republic Geothermal Inc.

[15] Raytheon Corporation.

[16] This commenter, Potlatch Corporation, proposed as a test that at least 25 percent of the steam, or useful energy, available be applied on an annual basis in industrial, commercial, heating or cooling uses.

[17] The Economic Regulatory Administration.

[18] Brooklyn Union Gas Company.

[19] Mechanical Technology Incorporated.

the "effective heat rate".[32] This form of efficiency evaluation has been widely used to compare cogeneration of electricity to conventional utility generation. For a typical backpressure steam turbine cogeneration facility the effective heat rate of electricity generation may be as low as 4500 BTU/kWh—twice the efficiency of central station utility generation.

The effective heat rate test has some serious drawbacks, however. The test looks only to the efficiency of electricity generation and ignores the balance of the cogeneration facility. While the effective heat rate of a topping turbine may be high, if only a small fraction of the energy produced is in the form of electricity, the overall system is essentially a boiler facility, and the aggregate energy conserved is minimal. Indeed, effective heat rates are most favorable for systems which produce little electricity and a large amount of steam. The effective heat rate is lower for combustion turbine and internal combustion cogeneration, as compared to steam, but such systems produce more electricity per unit of fuel used. When the efficiency of the entire system is computed in such a manner as to credit the quality as well as quantity of energy produced,[33] combustion turbine or internal combustion cogeneration systems consistently score higher than steam systems. Thus the effective heat rate test does not truly measure overall system efficiency, and is not an adequate measure of whether, in the aggregate, energy is conserved through cogeneration.

§ 292.205(a)(2)(ii) *Topping-cycle facilities using energy sources other than oil or natural gas.*

In the final rule, the Commission has decided not to impose efficiency standards for qualification of topping-cycle cogeneration facilities using energy sources other than oil or natural gas. The proposed rules contained standards for topping-cycle cogeneration facilities using energy sources other than coal or coal-derived fuels. The efficiency standards were proposed in response to two concerns. First, some energy sources may be viewed as limited in access. Use of such resources by one cogenerator deprives another, possibly more efficient cogeneration facility, of the opportunity to use the resource. Efficiency standards were proposed in order to ensure that the first cogenerator, to gain access to the resource, would build an efficient facility in the absence of an effective market for the resource.

The second concern dealt with a means of distinguishing a *bona fide* cogeneration facility from a small power production facility with incidental recovery and use of steam or heat. The Commission believed that some means was necessary to prevent small power production facilities from evading the statutory size limits. A standard setting forth minimum production of power and minimum recovery of heat was seen as a means of avoiding the qualification of "token" cogeneration facilities.

Neither concern is, however, relevant to the use of coal as a primary fuel. Coal is not characterized by limited access and it cannot be used as a primary fuel by small power production facilities. Therefore, the proposed rule contained no efficiency standards for facilities fueled by coal.

Most commenters addressing this question stated that the proposed standards were impossible to meet in many instances. More importantly, commenters questioned the basic rationale of applying efficiency standards. The limited access concept is complex, and some commenters missed the point, arguing that such resources are renewable or available in large quantity.

EPA pointed out that the degree to which limited access may affect the sort of facility constructed is unknown. The effects of limited access, if any, are likely to be site specific, and will vary with time. Even if these effects could be spelled out with certainty, the specification of appropriate efficiency criteria would be a difficult task at best. If a standard of thermal efficiency were set without detailed knowledge of both the technologies and patterns of resource development, the probable effect would simply be to stifle development of the resource.

The Commission concludes that the proposed cure is far worse than the suspected ailment. In addition, as was stated in the discussion addressing the operating standards, the 5 percent minimum amount of useful thermal output standard will assure that these facilities are *bona fide* cogenerators under these rules.

§ 292.205(b) *Efficiency standards for bottoming-cycle facilities.*

The proposed rule contained a two-part efficiency standard for bottoming-cycle cogeneration facilities. All facilities, except those using coal or coal-derived fuels, would have been required to meet the standards. The first part of the efficiency standard dealt with the heat engine. In order to qualify, a facility had to either convert 15 percent of the reject heat from the thermal process to mechanical energy, or in the alternative, achieve 40 percent of the ideal Carnot efficiency with the working fluid temperatures experienced. The second part of the standard simply required an overall energy efficiency of 60 percent for the entire facility.

Numerous commenters were critical of the proposed standards. Although a number of issues were addressed, a common concern was the counter-productive nature of efficiency standards for bottoming-cycle cogeneration facilities relying on reject heat. It was argued that because the heat would otherwise be wasted, efficiency standards would serve no fuel conservation purpose. The only effect of efficiency standards would be a limitation on the number of bottoming-cycle facilities which would be constructed.

Moreover, many commenters noted that the overall energy efficiency standard of 60 percent was overly restrictive, and in fact meaningless in many instances. The overall energy efficiency, as defined in the proposed rule, would be determined by the efficiency of the bottoming-cycle heat engine and the efficiency of the industrial thermal process. Typically the latter efficiency is predetermined by the nature of the process and the design of the industrial plant. When bottoming-cycle cogeneration equipment is added to an existing plant, the efficiency of that plant's energy utilization is irrelevant to the effectiveness of the bottoming cycle. Furthermore, the measurement of overall energy efficiency required under the proposed rules would be difficult, since such efficiency measurements are not a conventional practice.

The Commission recognizes the validity of these comments, and has therefore eliminated efficiency standards for most bottoming-cycle cogeneration facilities. The final rule contains an efficiency standard for only those facilities with oil or natural gas

[32] To compute a cogeneration facility's effective heat rate, an assumption is made that the thermal output of the facility would have to be supplied in any event. A certain quantity of fuel would be needed to satisfy the thermal load in the absence of cogeneration. For example, if a steam turbine topping-cycle cogeneration facility were not installed, a conventional steam boiler would raise the steam. With the topping-cycle system, slightly more fuel is burned to raise steam at a higher pressure than is needed for the thermal process. The steam is expanded in a turbine, generating electricity and exhausting steam at the proper pressure for the thermal process. Effective heat rate is computed by dividing the extra energy supplied to the facility by the electricity generated..

[33] A Btu of electricity, for example, is worth more than a Btu of low pressure steam. The steam may be used for heat, but it is not useful for lighting or operating a television set. The "Second Law Efficiency" concept accurately reflects the usefulness of various forms of energy.

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supplementary firing. The need for standards in this case was acknowledged by several commenters.

When supplementary firing is used in a bottoming-cycle cogeneration facility, more than reject heat is used to generate electricity. Scarce fossil fuels can be introduced without the inherent efficiency advantages of sequential use. In order to restrict the potential for abuse, the Commission has adopted a simple efficiency test similar to that suggested by one of the commenters. The standard relates only to facilities installation [24] of which began on or after March 13, 1980, and for which any of the energy input as supplementary firing is oil or natural gas. Paragraph (b)(1) specifies that the useful power output of the bottoming cycle must, during any calendar year, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing. The Commission notes that the fuels used in the thermal process "upstream" from the bottoming-cycle facility's power production system are not considered in this efficiency test. The use of the lower heating value, consistent with the proposed rules, is advantageous to cogenerators in that the latent heat of combustion water cannot be effectively recovered by any practical bottoming-cycle technology currently foreseeable.

§ 292.205(c) Exemption from incremental pricing.

One of the incentives for cogeneration is found not in PURPA but in the Natural Gas Policy Act of 1978 (NGPA). In section 206(c), the Commission is given the discretion to exempt qualifying cogeneration facilities from its incremental pricing program developed under Title II of the NGPA.

On September 28, 1979, the Commission issued final rules implementing the incremental pricing provisions of the Natural Gas Policy Act of 1978.[25] These rules provide, among other things, that natural gas used by "a qualifying cogeneration facility" shall be exempt from the incremental pricing provisions of the NGPA.[26] A qualifying cogeneration facility is defined in the regulations as a cogeneration facility which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[27]

In this paragraph, the Commission has set forth the requirements for exemption from incremental pricing. Paragraph (c)(1) allows that any topping-cycle cogeneration facility which is a qualifying facility under § 292.203(b), and, if not already required to do so, meets the operating and efficiency standards under paragraphs (a)(1) and (2)(i) of this section, or is a qualifying facility under Subpart E of this part, may obtain an exemption from incremental pricing for its natural gas use.

Paragraph (c)(2) enables natural gas used in bottoming-cycle cogeneration facilities and which is not exempt from incremental pricing under Subpart E of this part to obtain exemption under this subpart to the extent that reject heat emerging from the useful thermal energy process is made available for use for power production. The Commission feels that these requirements adequately reflect the goal of PURPA to encourage the efficient use of energy by cogeneration facilities. To the extent that a facility makes available its reject thermal energy to produce power, the Commission believes it should obtain the benefit of exemption from incremental pricing.

The Commission does not intend for this subpart to interfere with any exemptions provided under Subpart E. Therefore, paragraph (c)(3) provides that any person who obtained an exemption under Subpart E is not affected by this provision.

Paragraph (c)(4) provides that natural gas used for supplementary firing in any cogeneration facility is not eligible for exemption from incremental pricing under this subpart. However, natural gas used for supplementary firing of a bottoming-cycle facility would be exempted under the Commission's Order No. 49–A, to the extent that the facility generates electricity which is sold to a utility.[28]

When the final regulations under Phase II of incremental pricing take effect and the Commission can then better assess their implications, the Commission may wish to revise the exemptions from incremental pricing to cogeneration facilities, including the exemption provided in the Interim Rule under Subpart E.

§ 292.205(d) Waiver.

This paragraph provides that the Commission will consider waiving any of the standards described above upon a showing that the facility will produce significant energy savings.

§ 292.206 Ownership criteria.

Section 292.206 is designed to implement the statutory requirement that a qualifying small power production facility or cogeneration facility must be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities). Regarding this provision, the Commission notes that the Conference Report states that:

> [e]lectric utilities may participate in an entity which owns such (qualifying small power production or cogeneration) facilities with other persons, and such entity could qualify under these definitions.
>
> The test of this case is whether the entity which owns the facility is primarily engaged in the generation or sale of electric power other than in connection with its ownership of the cogeneration facilities or small power production facilities.[29]

Thus, either directly or through a subsidiary company, an electric utility could participate in the ownership of a qualifying cogeneration or small power production facility.

Several commenters noted that under a literal interpretation of the Conference Report's statement, several electric utilities could form a subsidiary which owned small power production or cogeneration facilities. Such a subsidiary would constitute an entity which is not primarily engaged in the generation or sale of electric power other than in connection with its ownership of cogeneration or small power production facilities. Under such an interpretation, the subject facilities would be eligible to receive qualifying status.

The Commission believes, however, that the thrust of section 201 of PURPA is to limit the advantages of qualifying status to cogeneration and small power production facilities which are not owned primarily by electric utilities or their subsidiaries. The proposed rule provided that if, based on the proportion of ownership by electric utilities, public utility holding companies, or subsidiaries of either, more than 50 percent of the entity which owns the cogeneration or small power production facility is comprised of these electric utility interests, then the facilities are not qualifying facilities. This language has been incorporated into these final rules; the comments on this section provided no sufficient reasons in the Commission's judgment for changing the percentage.

[24] In the case of bottoming-cycle cogeneration in which electric generating equipment is retrofitted to existing sources of industrial reject heat, the date at which installation begins is the date on which the retrofit is begun.

[25] 18 CFR Part 282, 44 FR 57226 (Oct. 8, 1979).

[26] 18 CFR 282.201(a).

[27] 18 CFR 282.202(e).

[28] See Order No. 49–A, issued December 27, 1979, in Docket No. RM79-14, 45 FR 21 (Jan. 2, 1980).

[29] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

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The Commission emphasizes the fact that nothing in this program limits the extent of utility ownership or operation of cogeneration or small power production facilities. The Commission notes the statement in the Conference Report that:

. . . it is also the intention of the conferees that the definition of "qualifying cogeneration facility" and "qualifying small power production facility" will not be construed as prohibiting or discouraging electric utilities from cogenerating.[20]

Utilities may not, however, qualify for the benefits under this program if their ownership interests exceed the limits set forth in this rule.

Both the provisions in section 3(17)(C)(ii) and 3(18)(B)(ii) of the Federal Power Act, as amended by section 201 of PURPA, use the term person in describing who may own a qualifying cogeneration facility and qualifying small power production facility. The Commission has incorporated the ownership criteria under this section of the regulations and has used the term—person—found in the statute.

A few commenters questioned whether a municipality (or any other agency or instrumentality of State or Federal government) falls within the definition of the term "person" as used in definitions (17) and (18) in section 3 of the Federal Power Act. It is the Commission's view that the term "person," for purposes of qualifying under this program, does include municipalities (or any other agency or instrumentality of State or Federal government). This view is supported by case law in which the courts have treated municipalities and other units of State and Federal government as persons under other sections of the Federal Power Act. *See, e.g., United States v. Public Utilities Commission of California*, 345 U.S. 295 (1953); and *New England Power Co. v. FPC*, 349 F.2d 258 (1st Cir. 1965). The cases touching on the issue of these agencies as persons are very expansive (see the *California Public Utility Commission* decision cited above which was decided by the Supreme Court in 1953). Therefore, under past practice, the Commission and the courts have not interpreted "person" to exclude a municipality or other unit of State and Federal government from the benefits of any action of the Federal Power Act.

In addition, in that there is no indication that the Congress meant to deny qualification to these agencies or instrumentalities, the Commission finds no policy grounds for denying these agencies or instrumentalities qualifying status. Therefore, both as a matter of law and as a matter of policy, the term "person" as used in section 3(17)(C)(ii) and 3(18)(B)(ii) includes these agencies or instrumentalities. The effect of this is to allow these agencies or instrumentalities the opportunity to participate in this program if they otherwise meet the standards for qualification set out in this subpart.

§ 292.207 *Procedures for obtaining qualifying status.*

This section sets forth the procedures for obtaining qualifying status. Paragraph (a)(1) provides that a small power production facility which meets the criteria for qualification set forth in § 292.203 is a qualifying facility. As discussed above, the Commission has eliminated the mandatory case-by-case qualification procedure contained in the proposed rule.

Paragraph (a)(2) requires any owner or operator of a facility qualifying under paragraph (a)(1) to furnish notice to the Commission. The contents of the notice shall contain the information required of an applicant for qualifying status in paragraph (b)(2)(i) through (b)(2)(iv) described below. The Commission is requiring such notice for purposes of monitoring the market penetration of qualifying facilities, in compliance with its responsibilities under the National Environmental Policy Act of 1969, as previously discussed in this preamble.

Paragraph (b) provides an optional procedure whereby the owner or operator of a small power production facility may, should it prove desirable, file an application with this Commission for certification that the facility or cogeneration facility is a qualifying facility. The application must contain enough information to enable the Commission to make an accurate finding that the facility should or should not be certified.

Specifically, paragraph (b)(i) through (v) provides that each application must contain the name and address of the applicant and the location of the facility, a brief description of the facility including a statement indicating whether such facility is a small power production facility or a cogeneration facility, the primary energy source used or to be used by the facility, the rated power production capacity of the facility, and the percentage of ownership by electric utilities, or public utility holding companies, or by any person owned by either.

Applications by owners or operators of small power production facilities must also contain the location of the facility in relation to any other small power production facilities within one mile of the facility owned by the applicant which use the same energy resources, and information identifying any planned usage of natural gas, oil or coal.

An application by a cogenerator must contain the date installation facility commenced, a description of the cogeneration of the facility, including whether the facility is a topping or bottoming cycle, and sufficient information to determine that any applicable efficiency or operating requirements have been met.

Paragraph (b)(5) sets forth the procedures to be used by the Commission to determine whether a facility is to be granted qualifying status. It provides that, within 90 days of the filing of a complete application, the Commission shall issue an order granting or denying the application, extending the time for issuance of an order, or setting the matter for hearing. If no order is issued within 90 days of the filing of the application, it shall be deemed to have been granted.

The Commission will rely on its existing procedures for any person to file a petition for reconsideration of any Commission action instead of employing the protest procedure contained in the proposed rule.

Several commenters, while offering support for the elimination of filing and notice requirements for smaller facilities, acknowledged the useful purpose that would be served by a requirement that a larger facility give notice to the affected utility of its qualifying status and its intention that such utility purchase its power. Accordingly, the Commission has provided a requirement in paragraph (c) that an electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kilowatts or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b).

Paragraph (d)(1) provides that the Commission may revoke the qualifying status of a facility if it ceases to comply with any of the statements contained in its application for Commission certification. The Commission may do so on its own motion, or upon a motion to reconsider any certification previously granted. In either case, the Commission will act only after providing an opportunity for a hearing. Paragraph (d)(2) provides that, prior to undertaking any substantial alteration of a qualifying facility, a small power producer or cogenerator may, should it prove

[20] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 89-90, 95th Cong., 2d Sess. (1978).

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desirable, apply to the Commission for a determination that the facility, as modified, will retain its qualifying status.

IV. Effective Date

The Conference Report indicates that rules respecting criteria for qualifying facilities be prescribed "as soon as practicable" in order that persons may ascertain in advance of construction or operation of any facility whether or not such facility will meet the criteria established. The Commission believes, therefore, that good cause exists under 5 U.S.C. 553(d) to make the rules promulgated in this order effective immediately.

These rules have been promulgated under the Federal Power Act, as amended by PURPA, and, therefore, a right to rehearing exists under section 313 of the Federal Power Act.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, (15 U.S.C. 791 *et seq.*), Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*), E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, (15 U.S.C. 3301, *et seq.*))

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

1. Part 292 of Subchapter K is amended by adding a new Subpart B to read as follows:

Subpart B—Qualifying Cogeneration and Small Power Production Facilities

Sec.

Authority: Public Utility Regulatory Policies Act of 1978, (16 U.S.C. 2601, *et seq.*), Energy Supply and Environmental Coordination Act, (15 U.S.C. 791 *et seq.*), Federal Power Act, as amended, (16 U.S.C. 792, *et seq.*), Department of Energy Organization Act, (42 U.S.C 7101 *et seq.*), E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, (15 U.S.C. 3301, *et seq.*))

Subpart B—Qualifying Cogeneration and Small Power Production Facilities

§ 292.201 Scope.

This subpart applies to the criteria for and manner of becoming a qualifying small power production facility and a qualifying cogeneration facility under sections 3(17)(C) and 3(18)(B), respectively, of the Federal Power Act, as amended by section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

§ 292.202 Definitions.

For purposes of this subpart:

(a) "Biomass" means any organic material not derived from fossil fuels;

(b) "Waste" means by-product materials other than biomass;

(c) "Cogeneration facility" means equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy;

(d) "Topping-cycle cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy;

(e) "Bottoming-cycle cogeneration facility" means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production;

(f) "Supplementary firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility;

(g) "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process;

(h) "Useful thermal energy output" of a topping-cycle cogeneration facility means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application;

(i) "Total energy output" of a topping-cycle cogeneration facility is the sum of the useful power output and useful thermal energy output;

(j) "Total energy input" means the total energy of all forms supplied from external sources other than supplementary firing to the facility;

(k) "Natural gas" means either natural gas unmixed, or any mixture of natural gas and artificial gas;

(l) "Oil" means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products; and

(m) Energy input in the case of energy in the form of natural gas or oil is to be measured by the lower heating value of the natural gas or oil.

§ 292.203 General requirements for qualification.

(a) *Small power production facilities.* A small power production facility is a qualifying facility if it:

(1) Meets the maximum size criteria specified in § 292.204(a);

(2) Meets the fuel use criteria specified in § 292.204(b); and

(3) Meets the ownership criteria specified in § 292.206.

(b) *Cogeneration facilities.* (1) Unless excluded under paragraph (c), a cogeneration facility is a qualifying facility if it:

(i) Meets any applicable operating and efficiency standards specified in § 292.205 (a) and (b); and

(ii) Meets the ownership criteria specified in § 292.206.

(2) For purposes of qualification of a cogeneration facility for exemption from incremental pricing, a cogeneration facility must qualify under § 292.205(c).

(c) *Interim exclusion.* (1) Pending further Commission action, any cogeneration facility which is a new diesel cogeneration facility may not be a qualifying facility.

(2) A new diesel cogeneration facility is a cogeneration facility:

(i) Which derives its useful power output from a diesel engine, and

(ii) The installation of which began on or after March 13, 1980.

§ 292.204 Criteria for qualifying small power production facilities.

(a) *Size of the facility*—(1) *Maximum size.* The power production capacity of the facility for which qualification is sought, together with the capacity of any other facilities which use the same energy resource, are owned by the same person, and are located at the same site, may not exceed 80 megawatts.

(2) *Method of calculation.* (i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.

(ii) For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility.

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(3) *Waiver.* The Commission may modify the application of subparagraph (2) for good cause.

(b) *Fuel use.* (1)(i) The primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 50 percent of the total energy input must be from these sources.

(ii) Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.

(2) Use of oil, natural gas, and coal by a facility may not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar year period.

§ 292.205 Criteria for qualifying cogeneration facilities.

(a) *Operating and efficiency standards for topping-cycle facilities*—(1) *Operating standard.* For any topping-cycle cogeneration facility, the useful thermal energy output of the facility must, during any calendar year period, be no less than 5 percent of the total energy output.

(2) *Efficiency standard.* (i) For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal energy output, during any calendar year period, must:

(A) Subject to paragraph (a)(2)(i)(B) of this section be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or

(B) If the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.

(ii) For any topping-cycle cogeneration facility not subject to paragraph (a)(2)(i) of this section there is no efficiency standard.

(b) *Efficiency standards for bottoming-cycle facilities.* (1) For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility must, during any calendar year period, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.

(2) For any bottoming-cycle cogeneration facility not covered by subparagraph (1) of this paragraph, there is no efficiency standard.

(c) *Exemption from incremental pricing.* (1) Natural gas used in any topping-cycle cogeneration facility is eligible for an exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978 (NGPA) and Part 282 of the Commission's rules if:

(i) The facility meets the operating and efficiency standards under paragraphs (a)(1) and (2)(i) of this section and is a qualifying facility under § 292.203(b)(1); or

(ii) The facility is a qualifying facility under Subpart E of this part.

(2) Natural gas used in any bottoming-cycle cogeneration facility, not subject to an exemption from incremental pricing under Subpart E of this part, is eligible for an exemption under Title II of the NGPA and Part 282 of the Commission's rules to the extent that reject heat emerging from the useful thermal energy process is made available for use for power production.

(3) Nothing in this subpart affects any exemption provided under Subpart E of this part.

(4) Natural gas used for supplementary firing in any cogeneration facility is not eligible under this part for exemption from incremental pricing.

(d) *Waiver.* The Commission may waive any of the requirements of paragraphs (a), (b) and (c) of this section upon a showing that the facility will produce significant energy savings.

§ 292.206 Ownership criteria.

(a) *General rule.* A cogeneration facility or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities).

(b) *Ownership test.* For purposes of this section, a cogeneration or small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power, if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by a public utility holding company, or companies, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or public utility holding company has an ownership interest of a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or public utility holding company.

§ 292.207 Procedures for obtaining qualifying status.

(a) *Qualification.* (1) A small power production facility or cogeneration facility which meets the criteria for qualification set forth in § 292.203 is a qualifying facility.

(2) The owner or operator of any facility qualifying under this paragraph shall furnish notice to the Commission providing the information set forth in paragraph (b)(2)(i) through (iv) of this section.

(b) *Optional procedure*—(1) *Application for Commission certification.* Pursuant to the provisions of this paragraph, the owner or operator of the facility may file with this Commission an application for Commission certification that the facility is a qualifying facility.

(2) *General contents of application.* The application shall contain the following information:

(i) The name and address of the applicant and location of the facility;

(ii) A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility;

(iii) The primary energy source used or to be used by the facility;

(iv) The power production capacity of the facility; and

(v) The percentage of ownership by any electric utility or by any public utility holding company, or by any person owned by either.

(3) *Additional application requirements for small power production facilities.* An application by a small power producer for Commission certification shall contain the following additional information:

(i) The location of the facility in relation to any other small power production facilities located within one mile of the facility, owned by the applicant which use the same energy source; and

(ii) Information identifying any planned usage of natural gas, oil or coal.

(4) *Additional application requirements for cogeneration facilities.* An application by a cogenerator for Commission certification shall contain the following additional information:

(i) A description of the cogeneration system, including whether the facility is a topping or bottoming cycle and sufficient information to determine that any applicable requirements under § 292.205 will be met; and

(ii) The date installation of the facility began or will begin.

(5) *Commission action.* Within 90 days of the filing of an application, the Commission shall issue an order granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify

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the specific requirements which were not met. If no order is issued within 90 days of the filing of the complete application, it shall be deemed to have been granted.

(c) *Notice requirements for facilities of 500 kW or more.* An electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kW or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b) of this section.

(d) *Revocation of qualifying status.* (1) The Commission may revoke the qualifying status of a qualifying facility which has been certified under this section if such facility fails to comply with any of the statements contained in its application for Commission certification.

(2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status.

Appendix I

Note.—This Appendix should not be included in the text of the regulations in the Code of Federal Regulations.

Summary of Comments on Preliminary Environmental Assessment

General. Numerous comments addressed the Environmental Assessment in general and discuss the need for a programmatic environmental impact statement (EIS).

Some of the comments favored an environmental impact statement. The New England Chapter of the Sierra Club stated that it is in accord with the general thrust of the Environmental Assessment. However, it is concerned with the encouragement of those technologies which utilize non-renewable energy resources and with those technologies which, if uncontrolled, tend to produce large quantities of pollutants. Therefore, the commenter stated that a generic EIS is needed to examine the absolute environmental effects of the rulemaking in encouraging all the assumed "benign" technologies.

This commenter also concurred with the suggestion that, pending issuance of a generic environmental impact statement, the Commission should proceed with the implementation of rules and regulations under sections 201 and 210 of PURPA, except for technologies which may result in significant impacts as a result of the rules. For these technologies, the comments recommended that the Commission should proceed promptly to produce a comprehensive generic environmental impact statement.

Southern Company Services suggested that while the requirement to file an environmental impact statement may temporarily discourage cogeneration or small power production, it appears to be the only procedure for determining the environmental acceptability of a qualifying facility.

The Solar Lobby endorsed preparation of an EIS only where the environmental consequences of a qualifying facility are clearly negative. This commenter recommended that the more benign technologies should be encouraged even while appropriate generic environmental impact studies are performed.

Arthur D. Nadler Associates added that the environmental impact statement requirements should be kept to a minimum and be consistent with the small size of the facilities generally associated with those technologies.

Other commenters are opposed to the idea of a generic EIS. The California Energy Commission argued that the Commission's Environmental Assessment is adequate and that an EIS should not be required, particularly since any individual qualifying facility will receive State and Federal environmental scrutiny before it is constructed.

The California Energy Commission also suggested that the delay in adopting these regulations while an EIS is prepared and issued would itself cause adverse environmental and socioeconomic effects. Arizona Public Service Company and Brooklyn Union Gas Company concurred with the thrust of California's comment that, "Qualifying facilities will be delayed or not developed if the regulations are not adopted immediately. The failure to develop these qualifying facilities in a timely fashion will result in increased air pollution and adverse socioeconomic impacts from the increased consumption of imported oil and other fossil fuels during the period until the regulations are issued."

The Missouri Public Service Commission stated that for residential cogenerators or small power production facilities, an environmental impact statement will work as a disincentive, hindering consumer efforts at alleviating the energy problem. This commenter noted that while section 201 and 210 rules do have an effect on the quality of the human environment, it is a very beneficial one in that this program offers some viable alternatives for easing the energy problem. "As little interference by government with its agencies should be the goal so that American ingenuity and know-how can flourish."

Pan Tech Management stated that the PURPA rules will not constitute an action that will significantly affect the environment. This commenter recommended that the Commission promulgate the proposed rule with appropriate modifications based on public comment, but that it should not withhold promulgation of any part of the rules pending preparation of an EIS. The Commission should, in this commenter's view, review case-by-case, certain locations where environmental quality may already be below the standard (i.e. non-attainment areas with regard to air quality criteria), thus precluding the implementation of certain technologies.

The Colorado Office of Energy Conservation suggested that a much more critical need than an EIS for small power producers is a social and economic impact analysis.

Cogeneration technologies and their environmental impacts.

With regard to cogeneration, the commenters generally suggested that diesel cogeneration in congested urban areas may have adverse air quality effects.

Consolidated Edison, Boston Edison and Union Electric and separate comments by Southern Company Services stated that the proliferation of relatively small diesel cogeneration units installed in residential and commercial buildings would significantly affect the environment. The joint comments noted that each individual unit would likely escape any meaningful environmental review by State and Federal environmental authorities under current regulations, and yet the cumulative impact could well be serious. It was asserted that the problem will be particularly acute in areas where the attainment of national ambient air standards already is marginal (most congested urban areas), and where increases in pollutant concentrations would restrict opportunity for urban development and economic recovery. It was further asserted that most of the cogeneration is likely to be diesel engines, which these commenters stated emit larger amounts of some critical pollutants, per unit of energy produced, than do properly designed central power station plants. The joint comments stressed that cogeneration facilities discharge pollutants in non-buoyant plumes at roof-top levels which it was claimed will cause far greater pollution concentrations at street levels where people live and breathe, than do the buoyant plumes from the high, free-standing stacks of powerplants.

One of the commenters, Consolidated Edison, stated that on-site electric generation using diesel engines with waste heat recovery systems is already an economic alternative to its electric service or, in some cases, a combination of its electric and steam services, for some 395 customers representing a combined peak load of more than 1,000 MW. As additional incentives are added to the already favorable tax and regulatory climate for cogeneration installations in its service area, the utility claimed that the potential for conversions from central station to on-site generation could increase.

Consolidated Edison cited several studies prepared at its request which indicated that nitrogen dioxide (NO_2) standards in Manhattan could be contravened with the addition of as little as 240 MW of diesel cogeneration facilities in that borough. Consolidated Edison also stated that the studies indicated that the primary annual air quality standard for sulfur dioxide (SO_2) will be exceeded after several hundred more megawatts of diesel cogeneration capacity are installed.

Thomas Casten, speaking on behalf of The Cogeneration Society of New York, criticized several assumptions used in the Consolidated Edison studies. First he stated that several of the cogeneration facilities which the studies assumed would be installed in New York City violate existing environmental laws, and, therefore would not be installed. Secondly, he stated that these studies assume that 75 percent of the cogeneration plants would be installed in Manhattan, where environmental impacts would be most severe. He noted that eighteen of nineteen existing cogeneration plants in New York city are located outside of Manhattan.

This commenter next criticized the assumption that more than one thousand megawatts of diesel cogeneration will be installed in the New York City area, on the basis that this figure seems to exaggerate greatly the likely amount of cogeneration capacity. In addition, he contended that the standards used for measuring the emissions were those used for truck and bus-type engines which operate at varying speeds. He stated that a typical diesel cogeneration facility would operate at a fairly constant speed; and that, at constant speeds, emissions are about one-fourth of those produced at varying speeds.

Finally, the commenter noted that these studies assumed that there would be no improvements in the environment resulting from other factors during the time that the one thousand megawatts of diesel cogeneration were projected to be installed in New York City.

Commonwealth Edison and Consolidated Edison suggested that noise produced by diesel engines is a very serious environmental impact, and that the impact in any specific area is independent of the total number of units in any region. These commenters recommended that an environmental noise impact assessment be prepared and the appropriate noise abatement measures be included in the on-site diesel-engine installations. This could be done, they asserted, by requiring potential cogeneration facilities to prepare a noise emission analysis showing that the emissions would not contravene local or State requirements.

Consolidated Edison, Boston Edison, Union Electric and Southern Company Services, Inc. recommended that in light of the serious environmental consequences which are likely to flow from these rules, it is incumbent upon the Commission to accompany its proposed rules with a draft environmental impact statement.

Furthermore, Consolidated Edison, Boston Edison, and Union Electric suggested that an environmental impact statement should be required with respect to each new cogeneration facility having the potential for a significant adverse impact on the environment. The comments stated that any proposed facility having a generating capacity of 500 kW or more would have such an impact and should require an EIS.

Brooklyn Union Gas Company surveyed eight companies with cogeneration facilities and concluded that no environmental problems have been associated with the operation of the facilities. The facilities obtained the required air emissions permits and have been operating in compliance with applicable air quality regulations.

Penti Aalto, a consultant, suggested that all types of cogeneration facilities be permitted without an EIS, subject to periodic review of the system as a whole. If problem areas appear, then appropriate action could be taken.

The New York State Public Service Commission proposed limiting qualifying status to suitable locations or limiting the density of qualifying facilities in any given area.

The New York State Energy Office stated that an EIS is not necessary at this time. It proposed as an alternative that the Commission consider imposing a direct limitation upon the density of diesel cogeneration in large populated urban areas since the preliminary EA concludes that the number and density of urban diesel cogenerators determines the environmental risk.

Small Power Production Facilities.

Solar Energy. The Colorado Solar Energy Association stated that nearly all solar electric options are far less damaging to the environment than fossil-fueled or nuclear electric generation. He noted that implementation of PURPA must not be delayed by requiring the preparation of lengthy and time consuming environmental impact statements for renewable energy based qualifying facilities.

Geothermal Energy. The New England Chapter of the Sierra Club suggested that geothermal power production using hot brine sources is acknowledged to pose problems of air and water pollution and a potential toxic waste disposal problem. This commenter recommended that since there are no immediate plans for small power plant construction using hot geothermal brine (it is their understanding that such power production is currently uneconomic), it seems unnecessary to promulgate rules to encourage its use prior to preparation of the generic EIS.

Small-Scale Hydropower. The State of Vermont—Agency of Environmental Conservation stated that the small hydro summary in the preliminary EA was incorrect in stating that instances are rare where there is significant impact from facilities being added to an existing dam. It was stated that as in the Bolton Falls project, or at Ball Mountain, the impact of development could be significant in terms of water quality, fishery habitat and production, recreation, and possibly aesthetics.

The New England Chapter of the Sierra Club suggested that run-of-river hydro installations suffer from the same siltation, turbidity, and biological oxygen demand problems as do generating capacity additions at existing dams. Because almost all new non-Federal hydroelectric projects must be licensed by the Commission and environmentally evaluated on a case-by-case basis, this commenter concurred with the promulgation of rules allowing qualification of small hydroelectric projects at existing dams. It was asserted that run-of-river hydroelectric projects, however, pose an additional problem: the potential for diversion of water from existing channels. Unless all run-of-river hydro projects are to be environmentally evaluated on case-by-case basis, this commenter recommended that qualifying status be withheld until after completion of the generic EIS.

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Municipal Waste. Wheelabrator-Frye, Inc. stated that the encouragement of small power production and cogeneration fueled by municipal solid waste does not constitute a "major federal action significantly affecting the quality of the human environment." This commenter stated that small power production facilities which use such a feedstock produce a significant net *positive* impact on the overall environment since they reduce dependence upon highly polluting "open dumping" practices and encourage more efficient community solid waste management practices. He cited as an example one of the projects sponsored by his firm which has achieved waste volume reduction of more than 90 percent through currently available mass combustion technologies. He suggested that the quantity of waste requiring land disposal sites, as a result of processing through such facilities, is greatly reduced and more readily controlled and contained.

This commenter also suggested that since current EPA standards governing State implementation plans and new source performance procedures assure the conformance of such projects with the attainment of national air quality standards, no environmental impact statement need be filed by these facilities.

However, the New England Chapter of the Sierra Club stated that incineration of municipal wastes for power production purposes presents a potential problem in the emission of toxic substances, especially the more volatile heavy metals like mercury, cadmium and lead. With the eventual issuance of EPA regulations implementing the Toxic Substances Control Act, these emissions will be regulated; at this time they are not. This commenter does not propose an exception for municipal waste, but is concerned that any Commission regulations which encourage the incineration of municipal waste should insist on appropriate control technology.

Biomass. The New York State Energy Office and the Hawaiian Sugar Planter's Association stated that a detailed Environmental Assessment is not warranted for any of the biomass fuels already in use at small power production facilities.

The Hawaiian Sugar Planter's Association suggested that, in large part, the PURPA incentives should operate to encourage sugar factories to make more efficient use of the biomass already being burned and more efficient use of the steam being produced.

The New England Chapter of the Sierra Club stated that emission, soil tilth, fertility, and land use questions are present for biomass fuel. This commenter is concerned with the social effects of industrialization of agricultural areas induced by new biomass cogeneration facilities. "Biomass generally will provide relatively small amounts of net energy per unit mass or volume. As a result, encouragement of new biomass cogeneration facilities will tend to increase rural industrialization because high transportation costs will attract industrial cogenerators to the source of the biomass."

This commenter stated that it is not necessary to require an environmental impact statement for existing facilities or biomass cogeneration which use on-site produced waste—such as sawdust. However, it was suggested that an impact statement for new biomass-based cogeneration facilities which import off-site produced forest or agricultural products for the purpose of cogeneration should be required. "Cogeneration based on the use of stockyard wastes, kelp or similar sources need not be excepted if a thorough generic EIS is planned."

The Solar Energy Research Institute suggested that it is a mistake to group all types of "biomass" generating facilities together for environmental scrutiny. Many biomass systems use biogas in a combustion turbine and have minimal environmental impacts. This commenter recommended that several different classes of "biomass" facilities be identified and that each be considered separately.

The American Paper Institute stated that it was concerned that the Commission staff may not have taken into account many of the environmental benefits of burning wood and other biomass fuels.

Potlatch Corporation suggested that the definition of biomass in the preliminary environmental assessment is unusual and narrow. "Well-recognized concepts of biomass include all plant material including by-products of manufacturing, harvesting, and growing."

Wind. Two commenters suggested that the environmental effects of large wind energy conversion systems (WECS) can be significant. The State of Vermont—Agency of Environmental Conservation raised several problem areas. The first is that electromagnetic interference (as with radio or telecommunications) is an unknown quantity at the moment, with disagreement as to the extent of disruption that will actually be caused by a large WECS.

The second problem discussed was road construction and site preparation, especially on the fragile areas such as sites above 2500 feet in elevation. The wind energy resource appears to exist predominately at these higher elevations, yet sites which may be desirable from a power point of view are fragile and easily disrupted. Loss of vegetation cover and erosion of soil are two of the main concerns.

A third problem raised by this commenter was that the noise pollution and visual impact of the WECS were not mentioned in the summary of the preliminary Environmental Assessment.

The Solar Energy Research Institute recommended that the environmental impacts of large wind machines may need more careful scrutiny than the preliminary EA acknowledged. It was asserted that difficulties with low frequency sound and land use impacts need careful attention.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Dockets Nos. RM79-54 and RM79-55]

Small Power Production; Order Granting in Part and Denying in Part Rehearing of Orders Nos. 69 and 70, and Amending Regulations

Issued: May 15, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order granting in part and denying in part rehearing of order Nos. 69 and 70, and amending regulations.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby adopts an order granting in part and denying in part petitions for amendment of Order Nos. 69 and 70. The Order amends four sections of the Commission's rules involving small power production. The amendments involve the definition of "total energy input," general requirements for qualification of new dual-fuel cogeneration facilities, fuel use criteria for qualifying small power production facilities, and the exemption of qualifying facilities from sections 19 and 20 of the Federal Power Act.

EFFECTIVE DATE: May 15, 1980.

FOR FURTHER INFORMATION CONTACT:
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SUPPLEMENTARY INFORMATION:

In the matter of Small Power Production and Cogeneration Facilities—Rates and Exemptions, Qualifying Status; order granting in part and denying in part rehearing of order Nos. 69 and 70, and amending regulations.

On February 19, 1980, the Federal Energy Regulatory Commission (Commission) issued Order No. 69, the "Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978" (PURPA) in Docket No. RM79-55.[1] The Commission received six applications for rehearing or reconsideration.[2]

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[1] 45 *Fed. Reg.* 12214 (February 25, 1980).

[2] Southern Company Services, Inc. (March 14, 1980), Essex Development Association (March 14, 1980), American Electric Power Service Corporation (March 14, 1980), Edison Electric Institute (March 20, 1980), Consolidated Edison Company and Boston Edison Company (March 20, 1980), and Colorado-Ute Electric Association, Inc. (April 11, 1980).

The Commission notes that, while there is no express statutory right to rehearing of rules issued under section 210 of PURPA, there is a statutory right to rehearing of rules issued under section 201 of PURPA, which amended the Federal Power Act (FPA) by adding sections 3(17)-3(22). The Commission's view is that Congress, in incorporating by reference the enforcement provisions of the Federal Power Act (Section 210h of PURPA), intended also to incorporate by reference the rehearing and judicial review provision of the Federal Power Act.

In addition, a case involving the Natural Gas Act and the Natural Gas Policy Act of 1978, the Court observed that

* * * It is often not possible to draw a precise line separating the boundaries of the two Acts. Implementation of many NGPA Provisions requires conduct by FERC authorized under both Acts. As a result, the promulgation of rules may entail the exercise of authority under both the NGA and the NGPA. *Exxe, Inc. v. Federal Energy Regulatory Commission*, 611 F.2d 554, 564-566 (5th Cir. 1980).

The Commission notes that section 210 of PURPA and sections 3(17)-3(22) of the FPA, as added by section 201 of PURPA, are, to a large extent, interrelated. Section 201 of PURPA establishes the criteria and procedures by which a cogeneration or small power production facility can become a "qualifying" facility; section 210 of PURPA establishes rates for sales and purchases of electric power to and from qualifying facilities [illegible]

Footnotes continued on next page

On March 13, 1980 the Commission issued in Docket No. RM79-54, Order No. 70, the "Final Rule Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration Facilities." [3] That rule established criteria and procedures whereby small power production and cogeneration facilities could determine if they were eligible to receive the rate benefits and exemptions set forth in the Commission's rules implementing section 210 of PURPA.

The Commission received four petitions for rehearing of Docket No. RM79-54. [4]

With the exception of arguments discussed below, these applications raised no new matters of fact or law.

Order No. 69

Interconnection § 292.303(c). Consolidated Edison Company (Con Ed), Boston Edison Company, and Edison Electric Institute (EEI) recommended that the Commission determine that the interconnection procedures set forth in sections 210 and 212 of the Federal Power Act (FPA) are applicable to qualifying facilities, rather than requiring electric utilities to interconnect with a qualifying facility as an act included within the obligation to purchase, and not requiring an evidentiary hearing and the rendering of certain findings required under sections 210 and 212 of the FPA. In the final rule, the Commission observed that section 212(e) of the FPA provides that no provision of section 210 of the FPA should be treated as an exclusive means of obtaining relief. [5] The Commission interpreted this provision to mean that the existence of any authority under section 210 of the FPA to require interconnection should not be interpreted as exclusive of any other interconnection authority available under any other law. The Commission interpreted section 210(a) of PURPA as providing a broad grant of authority to prescribe rules necessary to encourage cogeneration and small power production, including the authority to require interconnection.

In their application, Con Ed and Boston Edison argued that the fact that Congress prohibited the Commission from exempting any qualifying facility from the provisions of sections 210 or 212 of the FPA renders moot or irrelevant the express ability of the Commisison to resort to other authority to require interconnections. They state that while section 210(a) of PURPA provides the FERC with a broad mandate to prescribe rules as it determines necessary, the Congress, in section 210(e) specifically prohibited the Commission from exempting any qualifying facility from the provisions of sections 210 or 212 of the FPA. As a result, Con Ed and Boston Edison claim that to read section 210(a) of PURPA as granting the "very authority specifically denied in section 210(e) of PURPA is to render the latter subsection utter surplusage."

The primary question arising from these claims is the proper interpretation of section 210(e)(3)(B) of PURPA, which provides that qualifying facilities cannot be exempted from sections 210, 211, and 212 of the FPA.

Section 210 of the FPA grants to electric utilities, Federal power marketing agencies, and qualifying congenerators any small power producers the right to apply for a Commission order requiring interconnection. The "target" of such an interconnection order can be "any cogeneration facility, and small power production facility, or the transmission facilities of any electric utility." [6]

Thus, in the procedures set forth in sections 210 and 212 of the FPA, qualifying facilities may either be applicants for interconnection orders, or targets of such interconnection orders. These sections confer upon qualifying facilities the right to apply for interconnection orders; they also impose on qualifying facilities the obligation and liability to be subjected to interconnection orders.

Section 210(e) of PURPA sets forth categories of State and Federal laws from which qualifying facilities can be exempted. The intent of this exemption is to remove the burden associated with being subjected to regulations as an electric utility under the FPA, the Public Utility Holding Company Act, and State laws regulating rates and financial organizations of electric utilities. The Joint Explanatory Statement of the Committee of Conference (Conference Report) accompanying PURPA states that rate regulation of qualifying facilities is to be done in a "less burdensome manner than traditional utility-rate regulation." [7] It further notes that

> [t]he establishment of utility type regulation over (cogeneration and small power production facilities) would act as a significant disincentive to firms interested in cogeneration and small power production. [8]

Thus, by exempting qualifying facilities from this type of regulation, Congress relieved them from liabilities and requirements to which others (*viz.*, non-qualifying facilities) are subject. Use of the word "exempt" in this context is consistent with its definition: "to release or deliver from some liability or requirement to which others are subject." [9] To "exempt" qualifying facilities does not mean to deny them a privilege or right to which they would otherwise be entitled; to exempt means to relieve of undesirable responsibility or obligation.

Sections 210 and 212 provide that, if the Commission makes certain determinations, it can impose obligations on qualifying facilities, including requiring the physical connection of the qualifying facility with the applicant, the sale or exchange of electric energy, or an increase in transmission capacity necessary to carry out these provisions. The Commission believes it is from these obligations that section 210(e)(3)(B) provides that qualifying facilities may not be exempted. Unlike the interpretation proffered by Con Ed and Boston Edison this reading comports with the plain meaning of the statute and with the accepted use of the language. And because qualifying facilities remain liable to being a target to an order under sections 210 and 212 of the FPA, section 210(e)(3)(B) is not "render[ed] utter surplusage." [10]

Under Con Ed's and Boston Edison's reading, section 210(e)(3)(B) of PURPA would also mean that qualifying facilities may not be exempted from applying under section 210 of the FPA to the Commission for an order requiring

Footnotes continued from last page
utilities, and exempts qualifying facilities from certain State and Federal regulation. The relationship between the FPA and PURPA in this proceeding is thus similar to that between the NGA and the NCPA. For the reasons set forth in *Ecee*, the issues will be more clearly delineated, and the task of separating interrelated sections will be obviated. If these rulemakings are subject to review in the same forum. The Commission expects that any review of its order on rehearing in Docket Nos. RM79-54 and RM79-55, would occur in the Courts of Appeal, pursuant to section 313(b) of the FPA.

[3] 45 FR 17959 (March 20, 1980).

[4] Southern Company Services, Inc. (April 11, 1980), Consolidated Edison Company (April 14, 1980), Southern California Gas Company (April 14, 1980), Elizabethtown Gas Company (April 14, 1980).

[5] Section 212(e) of the FPA states that no provision of section 210 of the FPA shall be treated (1) as requiring any person to utilize the authority of such section 210 or 211 in lieu of any authority of law, or (2) as limiting, impairing, or otherwise affecting any other authority of the Commission under any other provision of law.

[6] Section 210(a)(1)(A), Federal Power Act.

[7] Conference Report in H.R. 4018, Public Utility Regulatory Policies Act of 1978, H.R. Rep. No. 1750, 95th Cong., 2d Sess. 97 (1978).

[8] *Id.*

[9] Webster's Third New International Dictionary (1976).

[10] Petition for Rehearing and Reconsideration, Con Ed and Boston Edison, *supra* note 1, Annex at 6.

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interconnection. The Commission notes that the ability to *apply* for an interconnection order is not a duty, liability, or requirement to which a qualifying facility is subject; it is a grant of standing to request the Commission to impose an obligation on another party (viz., a target of an interconnection order).[11]

Under Con Ed's reading, the Commission may not "exempt" a qualifying facility from this statutory privilege. Since, as noted previously, to exempt means to relieve of liabilities, and not be excluded from rights or privileges, this interpretation does not seem consonant with the plain meaning of the statutory language.

Transmission § 292.303(d). Southern Company Services, Inc. (Southern Company), stated that § 292.303(d) appears to prohibit an electric utility transmitting from a qualifying facility to another electric utility from levying a transmission charge. This interpretation is not the one intended by the Commission. The sentence in question states that "[t]he rate for purchase by the electric utility to which such energy is transmitted * * * shall not include any charges for transmission." This phrase is intended to limit the amount that the utility to which electric energy is ultimately delivered must pay. This sentence provides that the purchasing utility need purchase this energy at a rate which reflects the costs it can avoid as a result of making such a purchase, and that any costs incurred to deliver the energy to it are the responsibility of the selling qualifying facility. (The transmitting utility may, however, agree to bear some or all of the transmission costs.)

The Commission does intend that an electric utility which *transmits* energy from a qualifying facility to another electric utility be permitted to receive reimbursement for this transmission service. As noted by Southern Company Services, this intent is expressed in the preamble, where the Commission stated:

> In the case of electric utilities not subject to the jurisdiction of this Commission, these (transmission) charges should be determined under applicable State law or regulation which may permit agreement between the qualifying facility and any electric utility which transmits energy or capacity with the consent of the qualifying facility. For utilities subject to the Commission's jurisdiction under Part II of the Federal Power Act, these charges will be determined pursuant to Part II.[12]

Southern Company recommends that these provisions be added to section 292.303(d), in place of the sentence which provides that rates for purchases shall not include any charges for transmission. The Commission believes that the provision as issued is acceptable. With this clarification, the proper interpretation should be clear.

Exemptions § 292.601(b). On March 19, 1980, Essex Development Associates (Essex) filed a Motion for Clarification of Order No. 69. Essex observed that the Commission did not exempt qualifying facilities from sections 19 and 20 of the Federal Power Act (FPA or Act). Essex stated that these sections provide the Commission with discretionary jurisdiction to regulate rates and the issuance of securities by licensees under Part I of the Federal Power Act. Essex contends that the intent of section 210 of PURPA and of Order No. 69, is to eliminate utility-type regulation of cogenerators and small power producers, without regard to the status of the facility as a licensee under Part I of the Federal Power Act. Essex requests that the Commission amend Order No. 69 to exempt qualifying facilities from sections 19 and 20 of the FPA, or that the Commission waive its rights under sections 19 and 20 to regulate a qualifying small power producer.

It should be noted that section 210(e)(3)(C) of PURPA provides that no qualifying facility may be exempted from

> * * * any license or permit requirement under Part I of the Federal Power Act, any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

The threshold question is whether this section should be interpreted to prevent the exemption of qualifying facilities from sections 19 and 20 of the Federal Power Act.

The intent of section 210(e) of PURPA, and of § 292.601 of the Commission's regulations (exemption to qualifying facilities from the Federal Power Act), is to remove the disincentive associated with utility-type regulation.[13] In Order No. 69, the Commission exempted qualifying facilities from cost-of-service regulation of rates, and from regulation of securities to which jurisdictional public utilities are subject under Part II of the Federal Power Act. In addition, within the statutory parameters, the Commission exempted qualifying facilities from regulation as electric utilities under the Public Utility Holding Company Act, and from State regulation of rates and financial organization.

Regulation under Part II of the Federal Power Act chiefly involves regulation of rates and financial organization, while regulation under Part I of the Act concerns the licensing of hydroelectric projects. A licensed project under Part I of the Federal Power Act may also be a qualifying small power producer, if it meets the size and ownership requirements set forth in Order No. 70.[14]

In pertinent part, section 19 of the Federal Power Act provides that, as a condition of a license, a licensee "developing, transmitting, or distributing power for sale or use in public service," shall abide by the rate and service regulation of any duly constituted agency of the State in which such service is provided. If power is provided in a State in which there is no authorized regulatory commission to regulate the rates for sales of power, or the issuance of securities by a licensee, jurisdiction is conferred on the Commission to regulate these matters.

Section 20 of the FPA provides that, with regard to power from a licensed project that enters interstate or foreign commerce, the rate charged shall be "reasonable, nondiscriminatory, and just to the customer," and all "unreasonable discriminatory and unjust rates" are prohibited. It provides that if any State affected has not established a commission to enforce these requirements, or to regulate the issuance of securities, or if any parties or States are unable to agree on appropriate regulation, jurisdiction is conferred on the Commission to regulate these activities.

The Commission observes that most of the provisions of Part I of the Act impose conditions and restrictions on the construction and operation of hydroelectric facilities, which require that licensed projects comply with comprehensive development of the nation's waterways. As a result, the Commission perceives no inconsistency

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[11] Indeed, the ability to apply for an order imposing an obligation to wheel or transmit power is not conferred upon qualifying facilities; thus exclusion from being an applicant is an important distinction between sections 210 and 211 of the FPA.

[12] Order No. 70 supra, mimeo at 22.

[13] Conference Report to H.R. 4018, Public Utility Regulatory Policies Act of 1978, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 98 (1978).

[14] Section 292.206 of the Commission's rules provides that a facility cannot qualify if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or public utility holding companies. Section 292.204(a) provides that the power production capacity of a qualifying facility may not exceed 80 megawatts. Pursuant to § 292.601 (Order No. 69), only small power production facilities of 30 mw or less are exempted from the Federal Power Act, the Public Utility Holding Company Act, and State regulation, except biomass facilities between 30 and 80 megawatts which are exempt from State regulation and from the Public Utility Holding Company Act.

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in exempting licensed projects that are qualifying facilities from State and Federal regulation of rates and financial organization, and maintaining Federal regulation of the physical structure of such facilities, and their manner of operation. The Commission believes that the limitation on exemption from the Federal Power Act set forth in section 210(e)(3)(C) of PURPA was intended to ensure that licensees comply with the requirements concerning comprehensive development of waterways and ensure that they do not build or operate hydroelectric projects in a manner inconsistent with the public interest.

Nowhere in the legislative history of section 210, or in the Conference Report, does there appear any indication that qualifying facilities that are licensed hydroelectric projects were intended to be singled out for utility-type rate or securities regulation. To subject these licensed projects to such regulation would be inconsistent with the intent of this section of PURPA—to encourage cogeneration and small power production. Thus, the Commission finds no basis to subject small power producer licensees to regulation under sections 19 and 20 of the Act, when they would otherwise be exempted from utility-type regulation at both the Federal and State levels.[15]

Moreover, the Commission finds no basis to believe that section 210 of PURPA was intended to grant exemption from the regulations of rates and financial organization, and yet to retain the authority to impose regulation of rates and the issuance of securities for one class of small power producers.

Rules of statutory construction indicate that the Commission should look to the object to be accomplished, and the evils sought to be remedied.[16] Moreover, a statute should be construed so as to effect its purpose.[17] The Commission has cited the reference in the Conference Report regarding its disincentives associated with "utility type regulation." It further cites the Conference Report statement that

> [I]t is not the intention of the conferees that cogeneration and small power producers become subject * * * to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[18]

The authority contained in sections 19 and 20 of the Federal Power Act would reserve to the Commission the authority to impose this type of utility regulation on qualifying small power producer licensees. The possibility that such regulation will be imposed could reduce the encouragement of development of small power production which the Congress, in section 210 of PURPA, and the Commission, in Order No. 69, intended to provide. For the reasons set forth, the Commission finds it appropriate to exempt qualifying facilities from these sections of the Federal Power Act.

Accordingly, the Commission amends § 292.601(b)(1), so as to exempt qualifying facilities from sections 19 and 20 of the Federal Power Act.

Order No. 70

Definitions § 292.202. Sections 292.202(i) and 292.202(j), define the "total energy output" and "total energy input" of a qualifying facility. Dividing the total energy output by the total energy input indicates the efficiency of the facility.

In § 292.202(j) of the final rule, energy obtained from supplementary firing was inadvertently excluded from the definition of total energy input. Since energy from supplementary firing was not excluded from the definition of total energy *output*, the rule would distort the efficiency of facilities in which large amounts of energy are supplied from supplementary firing, making them appear more efficient than they are.

To correct this unintended result, the Commission is amending the definition of total energy input so that it includes energy supplied from supplementary firing. This change will be accomplished by deleting the clause "other than supplementary firing" from the definition of total energy input.

Ownership § 292.206(b). Southern California Gas Company (SCGC) and Elizabethtown Gas Company (Elizabethtown) contend that § 292.206(b) of the Commission's rules erroneously exclude from qualifying status facilities owned by public utility holding companies that are not engaged in the generation or sale of electricity other than from cogeneration facilities or small power production facilities. Elizabethtown states that the rules do not prohibit a gas distribution utility from owning a qualifying facility.

Sections 17(C)(ii) and 18(B)(ii) of the Federal Power Act require the Commission to limit qualifying status to facilities "owned by persons not primarily engaged in the generation or sale of electric power." Section 292.206 of the Commission's rules prohibits public utility holding companies from owning more than 50 percent of the equity interest of a qualifying facility.

The Commission did not intend to prohibit companies without any electric utility interests from owning qualifying facilities. However, because public utility holding companies are subject to many special restrictions, before changing this provision of its rules, the Commission believes it appropriate to consult with the Securities and Exchange Commission to determine whether permitting gas holding companies to own qualifying facilities is consistent with that agency's regulation of holding companies.

Fuel Use § 292.204(b)(1). Southern Company takes exception to the fuel use criteria employed by the Commission in defining a qualifying small power production facility under § 292.204(b) of the rules. In the proposed rule, the term "primary energy source" was not defined. In response to several comments that standards should be established for determining the primary energy source, the Commission required in § 292.204(b)(1) of the final rule that more than 50 percent of the total energy input of a qualifying facility be from biomass, waste, renewable resources, or any combination thereof.

Southern Company states that a small power production facility which utilizes biomass, waste, or renewable resources as its "primary energy source" no more than 51 percent of the time, complies with the "sole" use requirement of the PURPA definition. Southern Company contends that this standard should be eliminated in favor of a standard which requires a small power production

[15] The Commission observes that even if exemption from these provisions were not granted, the residual grant of authority to the Commission set forth in sections 19 and 20 is consistent with the rate and exemption provisions of section 210 of PURPA, and with Order No. 69. Section 210(b) provides that rates for purchases from qualifying facilities shall be "just and reasonable to the electric consumers of the electric utility and in the public interest, and shall not discriminate against qualifying facilities." Section 292.304(a) repeats these statutory requirements. Section 210(f) of PURPA and § 292.401 of the Commission's rules require that, within one year after the Commission's rules take effect, each State regulatory authority is to implement the rules issued by the Commission regarding rates for purchases and sales of electric energy and capacity between qualifying facilities and electric utilities. After State implementation takes place, compliance with section 19—whether viewed as State regulation in the first instance or residual Federal regulation—would be accomplished through the State's program implementing section 210 of PURPA and Order No. 69. Similarly, the requirements set forth in section 20 regarding the rates for power from licensed projects are not inconsistent with the requirements of section 210 of PURPA, or Order No. 69. Again, regulation under section 210 of PURPA would constitute the vehicle for regulation under section 20 of the Act. (For qualifying small power production facilities greater than 30 mw, where the facility is subject to Commission jurisdiction under Part II of the Federal Power Act, the Commission will establish rates for purchase in accordance with the avoided cost principles set forth in § 292.304.)

[16] 82 C.J.S. *Statutes* § 323.

[17] *Id.*

[18] Conference Report, *supra* note 13, at 97.

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facility to use a higher percentage of renewable resources, waste, or biomass.

Two provisions of the rules are involved in this issue. Section § 292.204(b)(2) provides that the oil, natural gas, and coal used by a qualifying facility may not, in the aggragate, exceed 25 percent of the total energy imput of the facility during any calendar year. As discussed in the preamble [19] comments received indicated that effective use of biomass or waste as fuels can require that as much as 25 percent of the heat input be from fossil fuel. To assure that these renewable resources qualify for the statutory benefits, the Commission adopted the "25 percent rule."

As noted above, § 292.204(b)(1)(i) provides that more than 50 percent of the total energy input to a qualifying small power production facility must be biomass, waste, renewable resources, or any combination thereof.

At this time, the Commission believes that there are virtually no eligible fuels which are feasible for use by a qualifying facility to fill the hiatus if it derives 50 percent of its energy input from biomass, waste or renewable resources, and 25 percent from oil, natural gas and coal. The Commission will accordingly amend this provision of its rule to require that at least 75 percent of the total energy input of a qualifying small power production facility be from biomass, waste, renewable resources, or any combination thereof.

§ 292.204(b)(2). Southern Company also contends that the Commission's 25 percent limit on fossil fuel use by qualifying facilities is too broad, and is inconsistent with national energy policy. Southern Company argues that the Commission should adopt individual standards for each category of fossil fuel use listed in section 201 of PURPA, as appeared in the notice of proposed rulemaking.[20]

The Commission rejects this petition. The Commission based the 25 percent standard on the comments filed which generally favored a uniform aggregate standard. Commenters argued that separate standards for startups, flame stabilization and outages are unnecessarily burdensome. They also claimed that some small power production technologies would be severely constrained by one of the standards while requiring little or no fossil fuel for other purposes.

[19] Order No. 70, *supra*, mimeo at 38–42.

[20] These categories include fuel used for ignition, startup, testing, flame stabilization, and control uses, and fuel used to alleviate or present unanticipated equipment outages and emergencies that would affect public health, safety or welfare. Section 3(17)(B), FPA.

Additionally, the Commission belives that to the extent oil and natural gas remain more expensive than other energy sources available to small power producers, there is an economic disincentive to use more fossil fuel than is absolutely necessary.

Southern Company stated that the Commission's rules are inconsistent with standards promulgated under the Powerplant and Industrial Fuel Use Act of 1978 (FUA). The Commission notes that the FUA is intended to encourage the burning of coal in conventional power plants and industrial fuel burning plants. In contrast, sections 201 and 210 of PURPA are intended to encourage the cogeneration and electric generation through the use of biomass, waste, and renewable resources. Coal may not be used by a qualifying small power production facility as a primary energy source. Southern Company argues that the Commission should adopt, in its rules, the definition of "primary energy source" set forth in the interim rules implementing the FUA. These rules provide that a facility's consumption of oil and gas may not exceed five percent of the facility's annual Btu output. While the use of five percent gas or oil may be sufficient in combination with coal fuel, the burning of biomass or waste can require a greater use of gas or oil. Comments indicate that if the Commission were to adopt the more stringent five percent standard, the operation of many of these energy sources would not be feasible. Consequently, the Commission does not find that its rules are inconsistent with FUA standards, and rejects this proposed revision of the rules.

§§ 292.203(b) and 292.205. Southern Company and Con Ed submit that the Commission's rules are inconsistent with national energy policy in that they allow cogeneration facilities to burn oil and natural gas. Both petitioners request that the Commission amend its rules to include fuel use criteria for cogeneration facilities which the Commission determines to be qualifying cogeneration facilities. The result, they contend, of the Commission's failure to include fuel use restrictions is to authorize the burning of oil or natural gas for generation of electricity in cogeneration units, which will displace electricity generated by coal, nuclear or hydro power.

Numerous comments on this issue were submitted during the rulemaking process. First, the Commission notes that these rules do not authorize any facility to burn oil or gas in contravention of any applicable Federal, State or local laws or regulations. Rather, their effect is to make facilities, some of which may be authorized to burn fossil fuels under other statutory authority, such as the FUA, eligible for the rate and exemption privileges set forth in section 210 of PURPA.

As noted in the preamble [21] the Commission believes that the legislative history, Congressional intent, and national energy policy support the use of oil and gas in cogeneration facilities. Section 206(c)(3) of the Natural Gas Policy Act, authorized the Commission to exempt gas used by qualifying cogeneration facilities from incremental pricing surcharges.

Furthermore, the Commission believes that economics will make the displacement of nuclear coal or hydro generated electricity by a cogenerator using oil or natural gas a rare occurrence. In most cases, electricity generated by a cogenerator using oil or gas fuels is more expensive than electricity generated by nuclear, coal or hydro facilities. As a result, market forces, rather than an additional layer of Federal fuel use regulation, can effectively determine the appropriate use of oil or gas. For the above reasons the Commission denies the petition for amendment of this section of the rule.

Notice § 292.207. Southern Company and Con Ed petitioned the Commission to amend § 292.207 of its rules. This provision requires all qualifying facilities to furnish notice to the Commission of their status as qualifying facilities, and to provide a brief description of the facility and other pertinent data. The petitioners requested that the Commission require an applicant for certification of qualifying status intending to interconnect with a utility to furnish notice to the appropriate State regulatory authority and the utility with which it would interconnect.

The Commission has recently amended § 292.207(b)(6) of its rules.[22] This amendment requires that all applications for Commission certification of qualifying status include a notice of such request for publication in the Federal Register. The Commission believes that publication will provide adequate notice of applications for qualifying status. The Commission, therefore, rejects the petitions for amendment of § 292.207 of its rules.

Southern Company also petitioned the Commission to amend § 292.207(c) of the rule. This paragraph states that an electric utility is not required to

[21] Order No. 70, *supra*, mimeo at 24–28.

[22] Amendment to Final Rule Providing That Applications For Commission Certification of Qualifying Status Contain a Notice for Publication in the Federal Register, Order No. 70-A, Docket No. RM79-54, May 5, 1980.

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purchase electric energy from a qualifying facility of 500 kilowatts or more until 90 days after the facility notifies the utility that it qualifies, or that it has applied to the Commission for qualification. Southern Company contended that this section implies that a utility is derelict if it does not begin purchasing power from a qualifying facility over 500 kilowatts within 90 days after the facility has notified the utility or applied to the Commission for certification as a qualifying facility. Southern Company believes that 90 days is not a sufficient time period in which it can adjust its system to receive the generation output of the qualifying facility. Southern Company requested amending § 292.207(c) to allow for a "reasonable time" in which it must begin purchasing power from a qualifying facility.

Southern Company has erroneously interpreted § 292.207(c). Section 292.207(c) must be read in conjuction with § 292.207(b)7 and § 292.308. These sections provide that a utility is required to purchase power from a qualifying facility only if the facility meets all safety requirements, and pays for the appropriate interconnection costs as determined by the State regulatory authority. The 90-day requirement set out in § 292.207(c) establishes a minimum time period in which a utility must purchase power from a qualifying facility which has met all other applicable safety and interconnection requirements of the regulations. A utility need not purchase power from a qualifying facility until it meets these requirements, even if the 90-day period has elapsed. The Commission believes this interpretation of the regulation allows for a reasonable time period in which a utility must purchase power from a qualifying facility. Therefore, the Commission rejects the petition for amendment of this section.

Procedures for Obtaining Qualifying Status § 292.207. Con Ed states that the self-certifying procedure for obtaining qualifying status fails to inform utilities whether a particular facility is qualified. Under the proposed rule, all determinations of qualifications would have required Commission action on a case-by-case basis. Comments received indicated that when no affected party questions the eligibility of a facility, there is no need to require filing for qualification. As noted in the preamble to Order No. 70, the initiation of negotations concerning purchase and sale arrangements allows for the flow of information between potential qualifying facilities and affected electric utilities.[23] If a utility considers that a facility does not qualify, it is not obligated to purchase its electric output. In such cases, the facility may seek Commission certification under § 292.207(b). The Commission expects that, for the great majority of facilities requesting that utilities purchase their electric output, there will be no disagreement as to their eligibility. In questionable cases, the rules as issued provide for Commission determination of the facility's status. Thus, the Commission perceives no need to require additional paperwork in uncontested determinations.

§ 292.206(d). Con Ed requested that the Commission amend § 292.206(d) to include a mechanism for monitoring facilities to assure that the requirements for obtaining qualifying status continue to be met.

The Commission believes that the administrative costs associated with monitoring large numbers of qualifying facilities would be prohibitive. The Commission notes that section 201 of PURPA amended the Federal Power Act and that these rules fall under the ambit of the enforcement provisions of sections 314 and 316 of the FPA. Under these provisions, an applicant that ceases to meet the requirements for qualifying status, and fails to notify the Commission pursuant to § 292.207(d)(2) may be subject to civil and criminal penalties. The Commission will investigate any complaints that qualifying requirements are not being met. As a result, the Commission believes it is not necessary to establish a monitoring system.

~~*Environmental Effects* § 292.203(c).~~ In the Environmental Assessment (EA) issued with Docket No. RM79-54 [24], the Commission determined that the incentives provided in this program will encourage the development of only one technology, commercial cogeneration primarily by new diesel engines, at a level where significant environmental effects may occur in the near-term. Con Ed contended that spark ignition and dual-fuel cogeneration engines will also be widely used in commercial applications and will produce a substantial environmental impact.

Con Ed's petition does not refer to the discussion contained in the Appendices to the EA, referred to in the Commission's Notice accompanying the EA. In Appendix C the Commission stated:

Dual-fuel engines and diesel engines are likely to be the primary equipment choice for commercial cogeneration. Combustion turbines are large (greater than about 1 MW) and cost about $900 to $1,000/Kw Thus, investors would be facing equipment costs of about $1,000,000 to install one of these units. Spark ignition engines (similar to large gasoline-fuel truck engines) are insufficiently sturdy to warrant their use in continuous duty cogeneration Despite the low capital costs for spark ignition engines compared with those for diesel engines, repair and maintenance costs for the former are substantially higher.

Commercial cogeneration users will use natural gas as a fuel for dual-fuel engines whenever gas is available or less expensive than diesel fuel. In rural areas and in some urban areas of the Middle Atlantic region, natural gas is not available and distillate fuel use is expected. Thus, in these areas cogenerators will choose diesel engines. In large urban areas, because natural gas is available for potential cogenerators, cogenerators will install dual-fuel engines to take advantage of low-priced natural gas, even though a dual-fuel engine costs 20% to 30% more initially. We cannot precisely estimate the percent of the 2,500 MW of capacity that will be found in large urban areas. We estimate, however, that cogeneration in larger urban regions may account for 25 percent to 75 percent of the total.[25]

If gas is available for commercial or residential use in urban areas in the Middle Atlantic region, the installation of a great number of dual-fuel cogeneration engines in these areas might adversely affect the environment. Pending further environmental analysis, the Commission has decided to require that dual-fuel cogeneration facilities obtain qualification on a case-by-case basis, pursuant to the procedures set forth in section 292.207(b) of the Commission's rules. Before permitting new dual-fuel facilities to qualify, the Commission will consider the emission characteristics of the facility, and the number of qualifying cogeneration facilities in the vicinity of the applicant.

The Commission Orders: (A) To the extent not granted above, the applications for rehearing and reconsideration of Order Nos. 69 and 70 filed by Southern Company Services, American Electric Power Service Corporation, Edison Electric Institute, Consolidated Edison Company, Boston Edison Company, Colorado-Ute Electric Association, Inc., Elizabethtown Gas Company and Southern California Gas Company are denied.

(B) Sections 292.202, 292.203, 292.204, and 292.601 are amended as set forth below effective on May 15, 1980.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*; Energy Supply

[23] Order No. 70, *supra*, *mimeo* at 18.

[24] Notice of No Significant Impact and Notice of Intent to Prepare Environmental Impact Statement, issued March 31, 1980, Docket No. RM79-54 *mimeo* at 44.

[25] EA, *supra*, Appendix C, *mimeo* at 7.

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and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*: Federal Power Act, as amended, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulation, as set forth below, effective May 15 1980.

By the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 292.202 is amended in paragraph (j), to read as follows:

§ 292.202 Definition.

* * * * *

(j) "total energy input" means the total energy of all forms supplied from external sources.

* * * * *

2. Section 292.203 is amended in paragraph (c) by adding at the end thereof new subparagraphs (3) and (4) to read as follows.

§ 292.203 General requirements for qualification.

* * * * *

(c) *Interim exclusion.* * * *

(3) Pending further Commission action, any cogeneration facility which is a new dual-fuel cogeneration facility which seeks to obtain qualifying status must follow the procedures set forth in § 292.207(b) of this section.

(4) A new dual-fuel cogeneration facility is a cogeneration facility:

(i) which derives its useful power output from an internal combustion piston engine capable of changing automatically between gas and oil operation, and

(ii) the installation of which began on or after May 15, 1980.

* * * * *

3. Section 292.204 is amended in paragraph (b)(1)(i) to read as follows:

§ 292.204 Criteria for qualifying small power production facilities.

* * * * *

(b) *Fuel use.* (1)(i) The primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 75 percent of the total energy input must be from these sources. * * *

4. Section 292.601 is amended in paragraph (b)(1), to read as follows:

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

* * * * *

(b) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Sections 1-18, and 21-30; * * *

[FR Doc. 80-15616 Filed 5-20-80; 8:45 am]

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18 CFR Part 292

[Docket No. RM80-62; Order No. 104]

Section 206(d) Exemption for Mechanical Cogeneration Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

Issued: October 23, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 206(d) of the Natural Gas Policy Act of 1978 (NGPA). These rules exempt mechanical cogeneration facilities from the incremental pricing of natural gas under Title II of the NGPA. Prior to taking effect, this rule must be submitted to the Congress for review.

EFFECTIVE DATE: Thirty days after transmittal to Congress, provided that neither House of Congress passes a Resolution of Disapproval, in accordance with section 507(b) of the NGPA.

FOR FURTHER INFORMATION CONTACT:
James Liles, Office of Regulatory Analysis, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8158
or
Adam Wenner, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8033.

SUPPLEMENTARY INFORMATION: On May 30, 1980, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking Exempting Mechanical Cogeneration Facilities from all Incremental Pricing Provisions of the Natural Gas Policy Act of 1978 (15 U.S.C. 3301 *et seq.* (NGPA).[1] This rule is intended to make available to mechanical cogeneration facilities the same exemption from incremental pricing of natural gas under Title II of the NGPA that is provided to electric cogeneration facilities.

Background

Title II of the NGPA requires that the natural gas used in certain industrial facilities be subject to incremental pricing by means of surcharges. Section 206 of the NGPA establishes certain exemptions from these incremental pricing surcharges. Section 206(c)(3) provides that incremental pricing shall not apply

> * * * to the extent provided by the Commission by rule [to] any qualifying cogenerator (as defined in section 3(18)(B) of the Federal Power Act, as amended by the Public Utility Regulatory Policies Act of 1978) (PURPA).

On September 18, 1979, the Commission issued rules implementing Title II of the NGPA and establishing a mechanism for the incremental pricing program. One provision of these rules implemented section 206(c)(3) of the NGPA for purposes of the incremental pricing program.[2] This provision exempted from the incremental pricing program all gas used for cogeneration by qualifying cogeneration facilities are defined in section 3(18)(B) of the Federal Power Act. However, at that time the Commission had not promulgated rules establishing the criteria for "qualifying cogeneration facilities" under section 3(18)(B) of the Federal Power Act. In order to facilitate the operation of the incremental pricing rules the Commission, on November 9, 1979, issued an interim rule for qualification of gas-fired cogeneration facilities for purposes of the incremental pricing program.[3] This interim rule established an exemption from incremental pricing for certain cogeneration facilities which were in existence and used natural gas as an energy input on or prior to November 1, 1979.[4]

On March 13, 1980, the Commission issued a final rule under section 201 of PURPA establishing requirements for a determination of qualifying status for small power production and cogeneration facilities.[5] This rule maintained the criteria for the exemption from incremental pricing established in the interim rule, and also established additional criteria for other facilities not previously eligible[6] for the exemptions from incremental pricing set forth in 18 CFR 282.202(e).

The application of these exemptions, however, is limited by section 3(18)(B) of the Federal Power Act to cogeneration facilities which produce *electric* energy, and other forms of useful energy. Cogeneration facilities which produce *mechanical* energy and other forms of useful energy are not eligible under the final rule in Docket No. RM79-54 for these exemptions from incremental pricing.

Mechanical cogeneration facilities can produce the same fuel efficiencies as can cogeneration facilities producing electric energy. The proposed rules reflected the Commission's belief that cogeneration facilities which produce mechanical energy should be afforded the same exemption from incremental pricing surcharges as is available to cogeneration facilities which generate electricity. Section 206(d) of the NGPA authorizes the Commission to exempt from incremental pricing "any other industrial facility or category thereof." The proposed rule represented an attempt to utilize this authority to place mechanical and electrical cogeneration on an equal footing vis-a-vis the exemption from incremental pricing. Any rule providing for an exemption by the Commission under section 206(d) is subject to Congressional review before it can become effective.

The Basis for a Section 206(d) Exemption

Cogeneration involves the production of both useful heat and power through the sequential use of energy. Shaft power, compressed air and hydraulic power are all variations of the high-grade energy form known as mechanical power or energy. Production of any of these mechanical energy forms, with

[1] 45 FR 38080 (June 6, 1980).

[2] 18 CFR 282.202(e), 44 FR 57726 (October 5, 1979).

[3] Docket No. RM79-64, issued November 9, 1979, 44 FR 65744 (November 15, 1979).

[4] 18 CFR 292.301-292.303, 44 FR 65744 (November 15, 1979).

[5] Order No. 70, issued March 13, 1980 in Docket No. RM79-54, "Final Rule Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration Facilities." 45 FR 17959 (March 20, 1980).

[6] 18 CFR 292.205(c).

utilization of the reject heat from a facility, represents energy-efficient cogeneration with an energy conservation potential similar to that available from cogeneration involving the production of electricity.

The incentive provided through the exemption of cogeneration from incremental pricing is intended to promote the efficient use of energy by cogeneration facilities. However, as noted, under the existing rules, only those cogeneration facilities which generate electricity are eligible for the exemption; those producing only mechanical power are excluded. Not only is this distinction inequitable, since energy resources may be conserved absent electrical generation, but it may create a significant incentive for needless capital investment. An industrial company with a need for mechanical power which could be obtained through cogeneration might have an economic incentive through lower natural gas prices to cogenerate electrical instead of mechanical power. This electricity would, in turn, be used to power electric motors, which would be used to drive the machinery. Thus, several intermediate steps would be taken to obtain mechanical power.

The expense of installing the generators and motors would be needlessly incurred, since the cogeneration prime mover could directly supply the required mechanical power. Moreover, the intermediate conversion to electricity would result in energy losses since motors and generators are always less than perfectly efficient. By making mechanical cogeneration facilities eligible for the exemption from incremental pricing, this rule would remove this incentive to install unneeded equipment.

In the proposed rule, the Commission emphasized that this rule will not affect any of the provisions of Order Nos. 69 or 70 which pertain to electrical cogeneration.[7] The final rule does, however, adopt certain terms and criteria similar to those used in Order No. 70 for qualifying electrical cogeneration facilities. In order to ensure that mechanical and electrical cogeneration facilities are afforded similar treatment under the incremental pricing provisions of the NGPA, the efficiency standards adopted are similar to those prescribed for electrical cogeneration facilities in Order No. 70.

[7] Order No. 69, 45 FR 12214 (February 25, 1980), and Order No. 70, 45 FR 17659 (March 20, 1980).

Summary of Comments

The Commission received thirteen comments to the proposed rule.[8] A public hearing, scheduled for July 1, 1980, was cancelled due to lack of public response. All of the thirteen comments expressed general support for the proposed rule; eight comments offered specific recommendations for revisions.

Measurement of Mechanical Power and Related Issues

The proposed rule provided that the useful mechanical power output of a cogeneration facility could be determined at the output of the prime mover—or at some further stage of energy conversion, at the discretion of the cogenerator. Comments were requested as to whether the term "output of the prime mover" is appropriate, and whether the determination of mechanical power output should be permissive in regard to the point of measurement. Comments were also requested on the feasibility of measuring mechanical power output.

Seven commenters addressed the related issue of mechanical power measurement.[9] To varying degrees, these commenters suggested that ongoing measurement of the mechanical power output of an engine is generally infeasible. The commenters requested that the proposed requirement for measurement of mechanical power be replaced with a requirement that mechanical power be estimated. The Commission believes that these requests have merit, and adopts this recommendation.

Since a calculation which is appropriate for one cogeneration facility may be unsuitable for another, the rules do not specify a specific mechanical estimation technique. Rather, calculations are to be based on standard engineering methods, and must reflect the calendar year period specified for the operating and efficiency standards. The location of the estimate is within the discretion of the cogenerator. Calculations may be based on the design characteristics of the prime mover, the equipment driven by the prime mover, or on actual measurements.

[8] American Cyanamid Company, American Paper Institute (API), Chemical Manufacturers Association (CMA), The Dow Chemical Company, Glass Packaging Institute (GPI), Masonite Corporation (Masonite), Monsanto Company, Northern Illinois Gas Company (NI-Gas), Potlatch Corporation (Potlatch), Republic Steel Corporation, The Standard Oil Company (SOHIO), Stauffer Chemical Company, and Sun Petroleum Products Company (Sun Petroleum).

[9] API, CMA, Masonite, NI-Gas, Potlatch, SOHIO, and Sun Petroleum.

NI-Gas requested a more specific definition of the term "prime mover." This commenter believed that the proposed rule was unclear as to whether, for example, a steam turbine or the boiler supplying steam to the turbine is the prime mover. A prime mover is a device which converts other forms of energy (such as thermal energy or chemical energy) into mechanical energy. The Commission is mindful, however, that any simple definition of such a fundamental concept may work to exclude some novel technology or innovation. The Commission has, therefore, decided not to add a definition of "prime mover" to the rules. Instead, the phrase "* * * at the output of the prime mover * * * " has been modified to read "* * * at the output of the steam turbine, combustion turbine, or other prime mover * * *" This change will serve to clarify the intent without running the risk of an overly narrow definition. Thus, in the NI-Gas example, the prime mover is the steam turbine.

Revised Language

Several commenters requested clarification of certain portions of the proposed rules, and offered alternative language. The American Paper Institute [APA] suggested that the statement of the operating and efficiency standards in § 282.211(c) be combined. With regard to rules on electrical cogeneration facilities, an operating standard was adopted for topping-cycle systems to ensure that *bona fide* cogeneration situation exists. Efficiency standards were adopted for topping-cycle systems using oil or gas to ensure efficient use of these scarce fuels. Exemption from incremental pricing is available to electrical cogeneration facilities only if both operating and efficiency standards are met. Since the Commission's sole concern with mechanical cogeneration facilities in this docket is exemption from incremental pricing—and the Commission has decided to afford the exemption to mechanical facilities on the same basis as electrical facilities—both operating and efficiency standards must be met in order for a mechanical cogeneration facility to qualify for an exemption. Since both standards are applicable in all cases, the Commission will accept API's recommendation and simplify the statement of the standards.

Technical Definitions

NI-Gas commented on the definition of mechanical cogeneration facility. The definition in the proposed rule limited the term "useful thermal energy" to energy "used for industrial or commercial heating or cooling purposes * * *" The definition of cogeneration

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facility in Order No. 70 is less restrictive. In that definition, the useful thermal energy must be "used for industrial, commercial, heating, or cooling purposes * * *" Each term—industrial, commercial, heating, and cooling—stands alone. Under this definition, the useful thermal energy may be used in an industrial (or commercial) process other than heating or cooling. Process steam, for example, may be used directly in a chemical reaction. Heating or cooling purposes which are neither industrial nor commercial are also permitted under the definition in Order No. 70. Residential heating uses, for example, would be included. NI-Gas recommends that the less restrictive language found in Order No. 70 be used to define a mechanical cogeneration facility. The Commission has adopted this recommendation.

NI-Gas also recommended that the definitions of mechanical cogeneration facility and supplementary firing be modified to indicate that only facilities covered by Phase I of incremental pricing are included. As mandated under Title II of the NGPA, the Commission is required to implement the incremental pricing program in two phases. The Phase I rules apply only to the use of natural gas by large industrial boiler fuel facilities. On May 7, 1980, the Commission issued Phase II rules in Docket No. RM80-10 expanding the scope of the incremental pricing program to other industrial uses of natural gas. This Phase II rule was submitted to Congress for a mandatory review prior to taking effect. On May 20, 1980, the House of Representatives passed a Resolution of Disapproval, and the Commission has since vacated its Phase II Order.[10] Therefore, only natural gas used as boiler fuel by large industrial facilities is now subject to incremental pricing. Both of NI-Gas's recommended modifications would explicitly restrict the definitions of mechanical cogeneration facility and supplementary firing to boiler fuel use of gas which is not otherwise exempt from incremental pricing. NI-Gas proposes these changes as an effort to "avoid needless confusion."

The Commission has decided not to adopt the recommended changes. The Commission believes that these recommendations would be likely to cause confusion at the end-user level. On the one hand, the definitions of basic terms would become strikingly different when applied to electrical or mechanical cogeneration facilities. Many end-users have both types of cogeneration in the same plant. On the other hand, the recommendations would make the definitions contingent upon the status of other exemptions, such as the agricultural use exemption.

Since other exemptions are themselves contingent upon various circumstances (alternative fuel tests or monthly gas consumption, for example) confusion would likely arise concerning the timing for filing for an exemption, and the time when such exemption would become effective. Moreover, future consideration of a second Phase II rule would likely require that the definitions of mechanical cogeneration facility and supplementary firing be substantially modified and expanded. On balance, the Commission does not believe that end-users who are not presently subject to incremental pricing will be confused by promulgation of an exemption in broad inclusive language.

The Glass Packaging Institute (GPI) recommends an expansion of the definition of cogeneration to include facilities in which no mechanical or electrical energy is produced. Certain energy conversion systems, while not producing electrical or mechanical energy, may displace the need for such energy. The example cited by GPI is a system in which reject thermal energy from an industrial process is used in an adsorption refrigeration unit rather than a bottoming-cycle mechanical drive. GPI claims that the absorption system displaces a requirement for electrical or mechanical power and, therefore, the entire system should be considered the functional equivalent of a cogeneration facility.

The Commission recognizes that a facility such as that described by GPI could be highly energy efficient. However, GPI's proposal would be difficult if not impossible to administer. The efficiency of a non-mechanical "cogeneration facility" would have to be determined on the basis of a hypothetical displaced system. Any such evaluation of *what might have been* rather than *what is* leaves room for serious differences of opinion. GPI mentions the possibility that a cogeneration use might be claimed where thermal output from a "bottoming-cycle" is used simply for space heating. GPI states that this situation could be expressly excluded by not allowing the displacement of electric resistance heating. But the owner of such a system could reasonably claim that an electric heat pump was displaced—much the same as GPI's example facility displaces an electric air conditioning unit. There would be no straighforward way to resolve such a dispute. For these reasons, the Commission has decided not to adopt GPI's recommendation. However, it notes that the facility described by GPI would not be subject to incremental pricing under the Phase I rule since it does not use natural gas as boiler fuel.

Efficiency Standards

The Masonite Corporation (Masonite) recommends that lower efficiency standards be used for qualification of mechanical power facilities than were used for electrical cogeneration facilities. Masonite suggests that the proposed 42.5 percent test set forth in § 282.209(b) (§ 282.211(c) in the proposed rule) be reduced to 38.5 percent. No recommendation is made concerning the 45 percent efficiency requirement for cogeneration facilities with less than 15 percent of total energy output in the form of thermal energy.

Masonite states that the Commission is "essentially ignoring the losses which occur between the electrical generator source and the end user." An example is given of two equivalent pump systems, one mechanical and the other driven by an electric motor receiving its power from an electrical cogeneration facility. Masonite explains that the electrical cogeneration facility would have to be sized larger than the mechanical system to account for "electrical transformation and transmission line losses * * * as well as power losses in the electrical motor." In order to adjust for such power losses, lower efficiency standards are recommended for the mechanical system.

Masonite is correct in recognizing that the Commission's rules ignore losses which occur between a generator and ultimate user of electricity. In this regard, in the preamble to the proposed rule, the Commission stated:

> The proposed rule does not require theoretical conversion of mechanical energy to an electrical energy equivalent. A cogenerator developing only mechanical power most probably desires this form of energy for use in his facility. It is appropriate to relate this mechanical energy to an equivalent efficiency standard, rather than to attempt a determination of what quantity of electricity could reasonable be generated from the cogenerator's mechanical power.[11]

The converse is equally true. The rule does not attempt to require determination of the quantity of electricity that would be necessary to serve a mechanical load. A cogenerator is presumed to produce energy in the form desired. The fact that other,

[10] Order Denying Rehearing and Revoking Amendments made by Order No. 83, issued August 1, 1980, in Docket No. RM80-10, 45 FR —— (August ——, 1980).

[11] 45 FR 38081 (June 6, 1980).

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hypothetical systems may be less efficient should not affect the qualification of an actual system. As a matter of policy, the Commission believes that cogeneration facilities producing either electrical or mechancial power output should be measured against a common standard of efficiency.

Multiple Steam Turbines

Two commenters, Masonite and SOHIO, made similar recommendations concerning the aggregation of cogeneration units at the same site. Masonite points out that turbines used for producing mechanical energy "are quite often smaller and more numerous in use at a site than those turbines driving electrical generators * * *" Both commenters suggest that aggregation of multiple mechanical power turbines at a single site be allowed for purposes of qualifying under the rules. SOHIO recommends that a plant with four or more prime movers or heating loads be permitted to qualify based on an overall plant steam balance.

SOHIO argues that a plant with many individual pieces of equipment "would not have the instrumentation required to measure power production, or the total heating load." The question of how mechanical energy may be measured has been addressed elsewhere. Meters and gauges are not required. A plant with many small turbines should not incur any extra cost of instrumentation.

Under the Commission's definition of "mechanical cogeneration facility" [12] a group of turbines may be considered as a single unit for purposes of the rule if each draws steam from, and exhausts steam to, common steam headers. In this situation, all of the turbines occupy the same position in the "cascade" of energy through a sequential process.

However, the Commission chooses not to adopt a rule which would allow an entire industrial plant to qualify for exemption on the basis of an overall steam balance. The purpose of this rule is to afford an exemption from incremental pricing to gas-fired cogeneration. The rule is not intended to exempt an entire industrial boiler fuel facility from incremental pricing on the grounds that the plant contains certain cogeneration applications. Only the cogeneration applications are eligible for exemption under this rule.

[12] Section 282.204(a)(1) (§ 282.211(a)(1) in the proposed rule) defines a "mechanical cogeneration facility" as equipment used to produce mechanical energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy. . . .

In the comments, SOHIO provided a diagram of an industrial facility containing a variety of backpressure and extraction steam turbines. This facility also contained an unspecified block of "heating and non-heating loads" served directly from the boiler and not part of any sequential use of energy. Such steam loads were considered by the Commission previously in promulgating rules under section 201 of PURPA.[13] In the preamble to those rules, the Commission stated:

> * * * many industries commonly route steam directly from their boilers to processes without expansion in a turbine. This practice is simply the raising of process steam; it is not cogeneration. The fact that some other steam from the same boiler is routed to cogeneration equipment does not mean that all steam from the boiler is used for cogeneration. The coincident raising of process steam relates to the cogeneration rules in two ways. First, any energy expended in raising such steam should not be entered into any efficiency calculations. Secondly, natural gas used for raising process steam is not rendered exempt from incremental pricing solely because the boiler may also supply steam for cogeneration.

The Commission further wishes to amplify that condensing mechanical drive turbines served directly from a boiler do not comprise cogeneration since there is no sequential use of energy.

Moreover, any topping-cycle mechanical cogeneration facility must meet the five percent useful thermal output standard under § 282.209(b) in order to qualify for exemption from incremental pricing. The standard requires that no less than five percent of the total energy output, during any calendar year period, be in the form of useful thermal energy. Thus a plant containing only mechanical drive and other non-thermal use of steam does not meet the requirement. This holding is analogous to the Commission's treatment of combined-cycle electric generation facilities under Order No. 70.[14]

Congressional Review and Effective Date

The rule set forth below is issued pursuant to section 206(d) of the NGPA. That section requires that such rule be submitted to the Congress for review prior to taking effect. After submission to each House of Congress, the rule may take effect following 30 days of continuous session of Congress (as set forth in subsection 507(b) of the NGPA) unless either House adopts a resolution of disapproval within that 30 day period.

[13] Docket No. RM79-54, Order No. 70, 45 FR 17981.

[14] 45 FR 17963, 17964 (March 20, 1980).

Accordingly, this rule will be effective on the day following expiration of the 30-day period for Congressional review.

In consideration of the foregoing, if neither House of Congress passes a Resolution of Disapproval of the regulations transmitted to them in this rulemaking within 30 days of Congressional review, as determined in accordance with section 507(b) of the NGPA, Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, is amended as set forth below, effective on the day following expiration of the 30-day Congressional review period.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. §§ 3301-3434)

By the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 282.203 is amended by deleting the introductory paragraph, and by adding a new paragraph (c) to read as follows:

§ 282.203 Exempt end-uses:

* * * * *

(c) *Exemption for mechanical cogeneration facilities under section 206(d).* Natural gas used in a mechanical cogeneration facility shall be exempt from incremental pricing according to the provisions set forth in § 282.209.

2. The Table of Contents for Sections for Part 282 is amended to add a new § 282.209 entitled "*Exemption for mechanical cogeneration facilities under NGPA section 206(d).*"

3. Part 282 is amended by adding a new § 282.209 to read as follows:

§ 282.209 Exemption for mechanical cogeneration facilities under NGPA section 206(d).

(a) *Definitions and general rules.* For purposes of this section:

(1) "Mechanical cogeneration facility" means equipment used to produce mechanical energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy.

(2) "Topping-cycle mechanical cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce useful mechanical power output, and the reject heat from such power production is then used to provide useful thermal energy.

(3) "Bottoming-cycle mechanical cogeneration facility" means a cogeneration facility in which the energy input to the facility is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used to produce mechanical power output;

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(4) "Supplementary firing" means an energy input to the mechanical cogeneration facility used only in the thermal process of a topping-cycle mechanical cogeneration facility, or only in the mechanical power production process of a bottoming-cycle mechanical cogeneration facility.

(5) "Useful mechanical power output" of a mechanical cogeneration facility means the total mechanical energy made available for use, exclusive of any such energy used in the mechanical energy production process;

(6) "Useful thermal energy output" of a topping-cycle mechanical cogeneration facility means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application:

(7) "Total energy output" of a topping-cycle mechanical cogeneration facility is the sum of the useful mechanical power output and useful thermal energy output;

(8) "Total energy input" means the total energy of all forms supplied from external sources;

(9) "Natural gas" means either natural gas unmixed, or any mixture of natural gas and artificial gas;

(10) "Oil" means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products;

(11) Energy input in the case of energy in the form of natural gas or oil is to be measured by the lower heating value of natural gas or oil; and

(12) Useful mechanical power output may be estimated at the output of the steam turbine, combustion turbine, or other prime mover or at a subsequent energy conversion point.

(b) *Exemption from incremental pricing for topping-cycle facilities.* Natural gas used in any topping-cycle cogeneration facility, other than gas used for supplementary firing, is eligible for an exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978 (NGPA) and Part 282 of the Commission's rules if the useful thermal energy output of the facility, during any calendar year period, is 5 percent or more of the total energy output;

(1) for facilities in which the useful thermal energy output is less than 15 percent of total energy output, the useful mechanical energy output of the facility plus one-half the useful thermal energy output, during any calendar year period, is equal to or greater than 45 percent of the total energy input of natural gas and oil to the facility; or

(2) for facilities in which the useful thermal output is 15 percent or more of the total energy output, the useful mechanical energy output of the facility plus one-half the useful thermal energy output, during any calendar year period, is equal to or greater than 42.5 percent of the total energy input of natural gas and oil to the facility.

(c) *Exemption from incremental pricing for bottoming-cycle facilities.*

(1) *General Rule.* Natural gas used in any bottoming-cycle mechanical cogeneration facility, other than gas used for supplementary firing, is eligible for an exemption under Title II of the NGPA and Part 282 of the Commission's rules to the extent that reject heat emerging from the useful thermal energy process is made available for use in mechanical power production.

(2) *Efficiency standard.* For any bottoming-cycle mechanical cogeneration facility using natural gas or oil for supplementary firing, the useful mechanical power output of the facility, during any calendar year period, must be 45 percent or more of the energy input of natural gas and oil for supplementary firing.

(d) *Supplementary firing.* Natural gas used for supplementary firing in any mechanical cogeneration facility is not eligible under this section for exemption from incremental pricing.

(e) *Waiver.* The Commission may waive any of the requirements of paragraphs (b) or (c) of this section upon a showing that the facility will produce significant energy savings.

[FR Doc. 80-33720 Filed 10-29-80; 8:45 am]

BILLING CODE 6450-85-M

18 CFR Part 292

[Docket No. RM81-2; Order No. 135]

Eligibility, Rates, and Exemptions for Qualifying and Utility-Owned Geothermal Small Power Production Facilities

Issued: March 23, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts a final rulemaking regarding eligibility, rates, and exemptions for qualifying and utility-owned geothermal small power production facilities. The Order implements the Energy Security Act amendments to the Federal Power Act and the Public Utility Regulatory Policies Act of 1978 concerning geothermal small power production facilities by amending Part 292 of the Commission's rules. Except with respect to the Public Utility Holding Company Act, this rulemaking implements the Energy Security Act amendments, only as they relate to geothermal small power production facilities of which a utility own less than 50 percent.

EFFECTIVE DATE: May 1, 1981.

FOR FURTHER INFORMATION CONTACT: Glenn Berger, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8033, or

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SUPPLEMENTARY INFORMATION:

In the matter of small power production and cogeneration facilities—eligibility, rates, and exemptions for qualifying and utility-owned geothermal small power production facilities.

On November 6, 1980, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking (NOPR)[1] which proposed rules to implement section 643 of the Energy Security Act of 1980 (ESA).[2] The ESA amended the Federal Power Act (FPA) and the Public Utility Regulatory Policies Act of 1978 (PURPA) by adding provisions relating to geothermal small power production. Except with respect to the Public Utility Holding Company Act (PUHCA) (15 U.S.C. 79), this rulemaking implements the ESA amendments only as they relate to geothermal small power production facilities of which a utility owns less than 50 percent. The ESA amendments relating to utility-owned geothermal small power production facilities will be the subject of a subsequent rulemaking.

I. Background

Section 201 of PURPA authorizes the Commission to prescribe rules under which small power production facilities and cogeneration facilities can obtain "qualifying" status and thus become eligible for the rates and exemptions set forth in the Commission's rules implementing sections 201 and 210 of PURPA.[3] Section 643(a) of the ESA is intended to clarify the authority of the Commission to classify geothermal resources as a "primary energy source" for the purpose of eligibility as a qualifying small power production facility under section 3(17)(A) of the FPA, as amended by section 201 of PURPA.[4]

Section 643(b) of ESA contains three amendments to section 210 of PURPA. Subsection 643(b)(1) amends section 210(a) of PURPA. Section 210(a) requires the Commission to prescribe rules necessary to encourage cogeneration and small power production. The ESA amendment to this section requires the Commission to prescribe rules to encourage "geothermal small power production facilities of not more than 80 megawatts capacity."

Section 643(b)(2) of ESA amends section 210(e)(1) of PURPA to authorize the Commission to exempt "geothermal small power production facilities of not more than 80 megawatts capacity" from the FPA, the PUHCA, and State laws and regulations respecting the rates or the financial or organizational regulation of electric utilities, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. Under this amendment, the Commission's exemptive authority is no longer limited to "qualifying" geothermal small power production facilities. Therefore, the Commission may exempt utility-owned

[1] 45 FR 74934 (1980).

[2] Pub. L. No. 96-294, 94 Stat. 611 (1980).

[3] Order No. 69, 45 FR 12214 (Feb. 25, 1980). Order No. 70, 45 FR 17959 (Mar. 20, 1980).

[4] It is the Commission's position that, even before the ESA amendments, geothermal facilities were eligible for qualification as small power production facilities. This view is based on the legislative history of PURPA. 125 Cong. Rec. S. 17808 (daily ed. October 9, 1978) (remarks of Senators Durkin and Jackson). The conference report of the ESA indicates that the legislation does not intend "to cast the FERC's present regulations under section 3(17) into doubt by reason of this amendment." S. Rep. No. 96-824, 96th Cong., 2nd Sess. 312 (1980).

geothermal small power production facilities (UGSPPF) from these laws and regulations.

Prior to amendment, section 210(e)(2) of PURPA limited the Commission's authority to exempt qualifying small power production facilities to those with a capacity of 30 megawatts or less.[8] Section 643(b)(3) of ESA increases the limit to "80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source * * *" Thus, the Commission may exempt any qualifying small power production facility using geothermal energy as the primary energy source from the laws and regulations specified in section 210(e)(1) of PURPA.

The NOPR also discussed exempting UGSPPFs from the laws, and regulations specified in section 210(e)(1) of PURPA, as well as extending the "avoided cost" rate to such facilities pursuant to section 210(a). Public comments addressing this proposal generally supported the exemption of UGSPPFs from the PUHCA. Comments were divided, however, regarding exemption of UGSPPFs from the remaining laws and regulations. In order to have more time to consider the latter comments, the Commission has decided to implement the ESA amendments to the FPA and PURPA concerning geothermal small power production in two rulemakings.

This rule implements the ESA amendments to the FPA and PURPA concerning qualifying geothermal small power production facilities. It also exempts UGSPPFs from the PUHCA. In a subsequent rulemaking the Commission will consider further the implications of exempting UGSPPFs from the FPA, and certain State laws. The Commission does not yet reach the issue of extending the "avoided cost" rate principals to such facilities.

The Commission received thirteen comments in response to the NOPR in this docket and has considered all the comments in the formulation of the final rule.

II. Section-by-Section Analysis

§ 292.204 Primary energy source.

Section 3(17)(A) of the Federal Power Act, as amended by section 201 of PURPA, defines a "small power production facility" as a facility which produces energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof, and which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts. The amendment contained in section 643(a)(1) of ESA states that geothermal resources are an eligible primary energy source for small power production facilities.

Section 292.204 of the Commission's rules sets forth criteria for qualifying small power production facilities. To reflect the changes required by section 643(a)(1) of ESA, the Commission is amending this section of its rules to make it clear that small power production facilities using geothermal resources as a primary energy source can be qualifying facilities. This change appears in § 292.204(b)(1)(i), where "geothermal resources" is added to the list setting forth the eligible primary energy sources of a qualifying small power production facility.

§ 292.202 Definitions.

The Commission is amending § 292.202 of its rules by adding a new paragraph (o) which defines "utility geothermal small power production facility" (UGSPPF) as a small power production facility which uses geothermal energy as the primary energy source, and of which more than 50 percent is owned either (1) by an electric utility, electric utility holding company or any combination thereof, or (2) by any company 50 percent or more of the outstanding voting securities of which are directly or indirectly owned, controlled, or held with power to vote, by an electric utility, electric utility holding company, or any combination thereof.

The proposed rule defined a "utility geothermal small power production facility as a * * * facility * * * of which an electric utility * * * owns more than 50 percent of the outstanding voting securities." Several commenters noted that it is not the facility which issues securities. The commenters correctly pointed out that a UGSPPF is an asset of a corporation, and it is the corporation which issues securities. The Commission agrees with the commenters and has redefined a UGSPPF to reflect the ownership arrangements between a utility and a geothermal small power production facility.

§ 292.601 Exemption of qualifying facilities from the Federal Power Act.

This section implements section 210(e)(2) of PURPA as amended by section 643(b)(3) of ESA. The ESA permits the Commission to exempt qualifying small power production facilities of up to 80 megawatts capacity using geothermal resources from regulation under the FPA, the PUHCA, and from State laws and regulations respecting rates or the financial or organizational regulation of electric utilities.

Section 292.601 of the Commission's rules is amended by increasing the size limitation for exemptions from the FPA from 30 to 80 megawatts for qualifying small power production facilities using geothermal energy as a primary energy source.

Under the proposed rule a UGSPPF was added to the definition of "qualifying facility" and thus was eligible for exemption from the FPA, the PUHCA, and from State laws and regulations respecting rates or the financial or organizational regulation of electric utilities. The proposed rule also discussed extending the "avoided cost" rate benefits of section 210(a) to a UGSPPF.

The comments filed by the State regulatory authorities and non-utility owners regarding this provision of extending the rate and exemption benefits to UGSPPFs. Some of these commenters argued that the Commission lacks the statutory authority to extend the PURPA section 210 benefits to utility-owned geothermal facilities. Utility companies and affiliated associations, on the other hand, generally favored the proposed rule.

The Commission believes it has the statutory authority under ESA to grant a UGSPPF all the exemptions under section 210(e) that a qualifying facility may obtain. Due to the overwhelming response of the State regulatory authorities, however, the Commission is withholding the exemptions from the FPA and State law at this time so it may further consider the implications of granting such exemptions. The Commission does not yet reach the issue of rate benefits pursuant to section 210(a).

Avoided Cost

Commenters noted that in some areas of the country the full "avoided cost" rate benefits are not needed to encourage geothermal small power production. The commenters suggest that, if the appropriate State regulatory authority determines that a rate less than avoided cost is sufficient to encourage rapid commercial development of geothermal small power production, the State regulatory authority should have the ability to set a lower rate for purchase.

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[8] Small power production facilities between 30 and 80 megawatts which use biomass as a primary energy source are exempt from the Public Utility Holding Company Act, and from State laws respecting the (wholesale) rates or financial or organizational regulation. See § 292.602 of the Commission's rules.

The Commission has considered this suggestion during its original rulemaking proceeding on cogeneration and small power production.[6] Some comments received during the original rulemaking recommended that, as a matter of policy, a State regulatory authority or non-regulated utility be given the discretion to establish the relationship between avoided cost and rate for purchases.

The Commission in § 292.304 of its rules decided to set the rate for purchases at full avoided cost. The Commission continues to believe that such a rate for purchase is necesssary to encourage cogeneration and small power production as required by section 210 of PURPA. A State regulatory authority is not precluded, however, from petitioning the Commission for a waiver of § 292.304 pursuant to § 292.403 of the Commission's rules.

§ 292.602 Exemption of qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

This section is amended in paragraph (b) by adding a "utility geothermal small power production facility" to the types of facilities which shall not be considered to be an electric utility company as defined in section 2(a)(3) of the PUCHC, 15 U.S.C. 79(b)(a)(3). Furthermore, the Commission is extending the exemption from the PUHCA for qualifying small power production facilities using geothermal energy from 30 to 80 megawatts.

The applicability of § 292.602 includes those facilities described in § 292.601(a) of the Commission's rules. Therefore, the exemption of qualifying small power production facilities of 80 megawatts or less using geothermal energy as a primary energy source is accomplished by the change to § 292.601(a) described above.

The Commission notes that the Securities and Exchange Commission (SEC) has issued a final rule, entitled "Rules Exempting Certain Acquisition by Electric Utility Companies and Exempting Such Companies as 'Holding Companies'."[7] The SEC adopted Rule 14, which exempts from the requirements of sections 9(a)(2) and 10 of PUHCA the acquisition by one or more electric utility companies of the securities of a power supply company. The SEC also adopted Rule 15 which provides an exemption from regulation as a "holding company" under section 3(a)(2) of the PUHCA for an electric utility company that makes any such acquisitions.

The grant of exemption in Rule 14 by the SEC would, however, require: (1) authorization to acquire voting securities by "the regulatory authorities having jurisdiction over the rates and service" of the parent utility; (2) the subsidiary generating company to supply all of the electricity it generates to its parent company or companies (with certain noted exceptions); and (3) that the issuance of securities by the generating company be "expressly authorized by a regulatory authority having jurisdiction over its rates and service."[8]

As indicated, the exemption under section 210(e) of PURPA eliminates the basis for the SEC's jurisdiction over acquisition and ownership of "qualifying" facilities or a UGSPPF. By excluding a UGSPPF from the definition of "electric utility company" under section 2(a)(3) of PUHCA, the Commission's rules eliminate the SEC's jurisdiction under section 9(a)(2) of PUHCA, thus rendering moot the exemption available under the SEC's Rules 14 and 15, as it pertains to geothermal facilities of 80 megawatts capacity or less.[9]

Environmental Conclusions

The Commission issued in June 1980, a draft environmental impact statement (DEIS) on rulemakings implementing sections 201 and 210 of PURPA. In the DEIS, the Commission determined that PURPA-induced development of geothermal small power production facilities would not create significant environment effects. In compliance with the National Environmental Policy Act of 1969 (NEPA), the Commission examined the environmental effects associated with these rules and has issued a Final Supplemental Environmental Impact Statement (EIS).[10]

The EIS accompanying this Order describes the environmental effects associated with the PURPA-induced development of small power production facilities using geothermal energy as a primary energy source. PURPA-induced development is anticipated in the near term for California, Nevada, and Idaho and may occur in other states in the West.

The revised rules under PURPA are expected to stimulate the development of up to 1,200 megawatts of electrical capacity from geothermal facilities by 1995. This is 1,100 megawatts more than predicted in the DEIS which the Commission prepared for the original rulemakings implementing sections 201 and 210 of PURPA.

The EIS found that geothermal resource development represents a relatively clean energy source and that increased geothermal development will reduce the adverse environmental impacts associated with nuclear and fossil fuel cycles.

III. Effective Date

These rules are effective May 1, 1981.

(Energy Security Act, Pub. L. No. [illegible]-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. [illegible] et seq., Energy Supply and Environmental Coordination Act, 15 U.S.C. [illegible] et seq., Federal Power Act, as amended, 16 U.S.C. [illegible] et seq., Department of Energy Organization Act, 42 U.S.C 7101 et seq., [illegible], 42 FR 462[illegible])

In consideration of the foregoing, the Commission amends Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 292.204 is amended by revising paragraph (b)(1)(i) to read as follows:

§ 292.204 Criteria [illegible] ing small power production [illegible]

* * * * *

(b) *Fuel Use.* (1)(i) The primary energy source of the facility must be biomass, waste, renewable resources, geothermal resources, or any combination thereof, and 75 percent or more of the total energy input must be from these sources.

* * * * *

2. Section 292.202 is amended by adding a new paragraph (o), to read as follows:

§ 292.202 Definitions.

* * * * *

(o) "Utility geothermal small power production facility" means a small power production facility which uses geothermal energy as the primary energy resource and of which more than 50 percent is owned [illegible]

(1) By an [illegible] electric [illegible] holding company [illegible] or any combination thereof, or [illegible]

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[6] 45 FR 12214, 12221 (Feb. 25, 1980).

[7] 46 FR 1687 (1981).

[8] *Id.* The exemptions are intended to facilitate joint ownership of conventional base-load generation plants, but also have application to non-conventional base-load generation plants.

[9] This approach is similar to the exemption from PUHCA contained in section 9 of the Pacific Northwest Electric Power Planning and Conservation Act (S. 885), which would exempt a "generating company" from the definition of an electric utility company in PUHCA. The SEC has indicated its support, in principle, for that exemption.

[10] Western Regional, Final Supplemental Environmental Impact Statement, Small Power Production and Cogeneration Facilities—Eligibility, Rates and Exemptions for Qualifying and Utility-Owned Geothermal Small Power Production Facilities, Docket No. RM81-2, February 1981.

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(2) By any company 50 percent or more of the outstanding voting securities of which of which are directly or indirectly owned, controlled, or held with power to vote by an electric utility, electric utility holding company, or any combinati[illegible] thereof.

3. Section 292.601 is revised to read as follows:

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to qualifying facilities, other than those described in paragraph (b).

(b) *Exclusion.* This section does not apply to a qualifying small power production facility with a power production capacity which exceeds 30 megawatts, if such facility uses any primary energy source other than geothermal resources.

(c) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Section 1–18, and 21–30;

(2) Sections 202(c), 210, 211, and 212;

(3) Sections 305(c): and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (c)(1), (2) and (3) of this section.

4. Section 292.602 is amended by revising paragraph (b) to read as follows:

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

* * * * *

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) or a utility geothermal small power production facility shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

* * * * *

[FR Doc. 81-[illegible] Filed 3-27-81; 8:45 am]
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United States - Federal

TAB 4

Energy Policy Act of 1992
Title I (Energy Efficiency)
Subtitle B (Utilities)

provements (including solar water heaters, solar-assisted air conditioners and ventilators, super-insulation, and insulating glass and film) and that has the effect of not disqualifying a borrower who, but for the expenditures on energy saving construction or improvements, would otherwise have qualified for a base loan.

(4) The term "residential building" means any attached or unattached single family residence.

(d) RULE OF CONSTRUCTION.—This section may not be construed to affect any other programs of the Secretary of Housing and Urban Development for energy-efficient mortgages. The pilot program carried out under this section shall not replace or result in the termination of such other programs.

(e) REGULATIONS.—The Secretary shall issue any regulations necessary to carry out this section not later than the expiration of the 180-day period beginning on the date of the enactment of this Act. The regulations shall be issued after notice and opportunity for public comment pursuant to the provisions of section 553 of title 5, United States Code (notwithstanding subsections (a)(2), (b)(B), and (d)(3) of such section).

(f) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated such sums as may be necessary to carry out this section.

Subtitle B—Utilities

SEC. 111. ENCOURAGEMENT OF INVESTMENTS IN CONSERVATION AND ENERGY EFFICIENCY BY ELECTRIC UTILITIES.

(a) AMENDMENT TO THE PUBLIC UTILITY REGULATORY POLICIES ACT.—The Public Utility Regulatory Policies Act of 1978 (P.L. 95-617; 92 Stat. 3117; 16 U.S.C. 2601 and following) is amended by adding the following at the end of section 111(d):

"(7) INTEGRATED RESOURCE PLANNING.—Each electric utility shall employ integrated resource planning. All plans or filings before a State regulatory authority to meet the requirements of this paragraph must be updated on a regular basis, must provide the opportunity for public participation and comment, and contain a requirement that the plan be implemented.

"(8) INVESTMENTS IN CONSERVATION AND DEMAND MANAGEMENT.—The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

"(9) ENERGY EFFICIENCY INVESTMENTS IN POWER GENERATION AND SUPPLY.—The rates charged by any electric utility shall be such that the utility is encouraged to make investments

in, and expenditures for, all cost-effective improvements in the energy efficiency of power generation, transmission and distribution. In considering regulatory changes to achieve the objectives of this paragraph, State regulatory authorities and nonregulated electric utilities shall consider the disincentives caused by existing ratemaking policies, and practices, and consider incentives that would encourage better maintenance, and investment in more efficient power generation, transmission and distribution equipment.".

(b) PROTECTION FOR SMALL BUSINESS.—The Public Utility Regulatory Policies Act of 1978 (P.L. 95-617; 92 Stat. 3117; 16 U.S.C. 2601 and following) is amended by inserting the following new paragraph at the end of subsection 111(c):

"(3) If a State regulatory authority implements a standard established by subsection (d)(7) or (8), such authority shall—

"(A) consider the impact that implementation of such standard would have on small businesses engaged in the design, sale, supply, installation or servicing of energy conservation, energy efficiency or other demand side management measures, and

"(B) implement such standard so as to assure that utility actions would not provide such utilities with unfair competitive advantages over such small businesses.".

(c) EFFECTIVE DATE.—Section 112(b) of such Act is amended by inserting "(or after the enactment of the Comprehensive National Energy Policy Act in the case of standards under paragraphs (7), (8), and (9) of section 111(d)" after "Act" in both places such word appears in paragraphs (1) and (2).

(d) DEFINITIONS.—Section 3 of such Act is amended by adding the following new paragraphs at the end thereof:

"(19) The term 'integrated resource planning' means, in the case of an electric utility, a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

"(20) The term 'system cost' means all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, distribution, transportation, utilization, waste management, and environmental compliance.

"(21) The term 'demand side management' includes load management techniques.".

(e) REPORT.—Not later than 2 years after the date of the enactment of this Act, the Secretary shall transmit a report to the President and to the Congress containing—

(1) a survey of all State laws, regulations, practices, and policies under which State regulatory authorities implement the provisions of paragraphs (7), (8), and (9) of section 111(d) of the Public Utility Regulatory Policies Act of 1978;

(2) an evaluation by the Secretary of whether and to what extent, integrated resource planning is likely to result in—

(A) higher or lower electricity costs to an electric utility's ultimate consumers or to classes or groups of such consumers;

(B) enhanced or reduced reliability of electric service; and

(C) increased or decreased dependence on particular energy resources; and

(3) a survey of practices and policies under which electric cooperatives prepare integrated resource plans, submit such plans to the Rural Electrification Administration and the extent to which such integrated resource planning is reflected in rates charged to customers.

The report shall include an analysis prepared in conjunction with the Federal Trade Commission, of the competitive impact of implementation of energy conservation, energy efficiency, and other demand side management programs by utilities on small businesses engaged in the design, sale, supply, installation, or servicing of similar energy conservation, energy efficiency, or other demand side management measures and whether any unfair, deceptive, or predatory acts exist, or are likely to exist, from implementation of such programs.

SEC. 112. ENERGY EFFICIENCY GRANTS TO STATE REGULATORY AUTHORITIES.

(a) ENERGY EFFICIENCY GRANTS.—The Secretary is authorized in accordance with the provisions of this section to provide grants to State regulatory authorities in an amount not to exceed $250,000 per authority, for purposes of encouraging demand-side management including energy conservation, energy efficiency and load management techniques and for meeting the requirements of paragraphs (7), (8), and (9) of section 111(d) of the Public Utility Regulatory Policies Act of 1978 and as a means of meeting gas supply needs and to meet the requirements of paragraphs (3) and (4) of section 303(b) of the Public Utility Regulatory Policies Act of 1978. Such grants may be utilized by a State regulatory authority to provide financial assistance to nonprofit subgrantees of the Department of Energy's Weatherization Assistance Program in order to facilitate participation by such subgrantees in proceedings of such regulatory authority to examine energy conservation, energy efficiency, or other demand-side management programs.

(b) PLAN.—A State regulatory authority wishing to receive a grant under this section shall submit a plan to the Secretary that specifies the actions such authority proposes to take that would achieve the purposes of this section.

(c) SECRETARIAL ACTION.—(1) In determining whether, and in what amount, to provide a grant to a State regulatory authority under this section the Secretary shall consider, in addition to other appropriate factors, the actions proposed by the State regulatory au-

thority to achieve the purposes of this section and to consider implementation of the ratemaking standards established in—

(A) paragraphs (7), (8) and (9) of section 111(d) of the Public Utility Regulatory Policies Act of 1978; or

(B) paragraphs (3) and (4) of section 303(b) of the Public Utility Regulatory Policies Act of 1978.

(2) Such actions—

(A) shall include procedures to facilitate the participation of grantees and nonprofit subgrantees of the Department of Energy's Weatherization Assistance Program in proceedings of such regulatory authorities examining demand-side management programs; and

(B) shall provide for coverage of the cost of such grantee and subgrantees' participation in such proceedings.

(d) RECORDKEEPING.—Each State regulatory authority that receives a grant under this section shall keep such records as the Secretary shall require.

(e) DEFINITION.—For purposes of this section, the term "State regulatory authority" shall have the same meaning as provided by section 3 of the Public Utility Regulatory Policies Act of 1978 in the case of electric utilities, and such term shall have the same meaning as provided by section 302 of the Public Utility Regulatory Policies Act of 1978 in the case of gas utilities, except that in the case of any State without a statewide ratemaking authority, such term shall mean the State energy office.

(g) AUTHORIZATION.—There are authorized to be appropriated $5,000,000 for each of the fiscal years 1994, 1995 and 1996 to carry out the purposes of this section.

SEC. 113. TENNESSEE VALLEY AUTHORITY LEAST-COST PLANNING PROGRAM.

(a) IN GENERAL.—The Tennessee Valley Authority shall conduct a least-cost planning program in accordance with this section.

(b) CONDUCT OF PROGRAM.—

(1) IN GENERAL.—In conducting a least-cost planning program under subsection (a), the Tennessee Valley Authority shall employ and implement a planning and selection process for new energy resources which evaluates the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources) in order to provide adequate and reliable service to electric customers of the Tennessee Valley Authority at the lowest system cost.

(2) PLANNING AND SELECTION PROCESS.—The planning and selection process referred to in paragraph (1) shall—

(A) take into account necessary features for system operation, including diversity, reliability, dispatchability, and other factors of risk;

(B) take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and

(C) treat demand and supply resources on a consistent and integrated basis.

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(3) SYSTEM COST DEFINED.—As used in paragraph (1), the term "system cost" means all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, transportation, utilization, waste management, environmental compliance, and, in the case of imported energy resources, maintaining access to foreign sources of supply.

(c) PARTICIPATION BY DISTRIBUTORS.—

(1) IN GENERAL.—In conducting a least-cost planning program under subsection (a), the Tennessee Valley Authority shall—

(A) provide an opportunity for distributors of the Tennessee Valley Authority to recommend cost-effective energy efficiency opportunities, rate structure incentives, and renewable energy proposals for inclusion in such program; and

(B) encourage and assist such distributors in the planning and implementation of cost-effective energy efficiency options.

(2) ASSISTANCE.—The Tennessee Valley Authority shall provide appropriate assistance to distributors under paragraph (1)(B). Such assistance shall, where cost effective, be provided by the Tennessee Valley Authority acting through, or in cooperation with, an association of distributors. Such assistance may include publications, workshops, conferences, one-on-one assistance, financial assistance, equipment loans, technology assessment studies, marketing studies, and other appropriate mechanisms to transfer information on energy efficiency and renewable energy options and programs to customers.

(d) PUBLIC REVIEW AND COMMENT.—Before the selection and addition of a major new energy resource on the Tennessee Valley Authority system, the Tennessee Valley Authority shall provide an opportunity for public review and comment and shall include a description of any such action in an annual report to the President and Congress.

(e) EXEMPTION FROM CERTAIN REQUIREMENTS.—The Tennessee Valley Authority shall not be subject to the least-cost planning requirements contained in section 111(d) of the Public Utility Regulatory Policies Act of 1978 or any similar requirement which might arise out of the Tennessee Valley Authority's electric power transactions with the Southeastern Power Administration.

SEC. 114. AMENDMENT OF HOOVER POWER PLANT ACT.

Title II of the Hoover Power Plant Act of 1984 (42 U.S.C. 7275–7276, Public Law 98–381) is amended to read as follows:

"TITLE II—INTEGRATED RESOURCE PLANNING

"SEC. 201. DEFINITIONS.

"As used in this title:

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"(1) The term 'Administrator' means the Administrator of the Western Area Power Administration.

"(2) The term 'integrated resource planning' means a planning process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

"(3) The term 'least cost option' means an option for providing reliable electric services to electric customers which will, to the extent practicable, minimize life-cycle system costs, including adverse environmental effects, of providing such service. To the extent practicable, energy efficiency and renewable resources may be given priority in any least-cost option.

"(4) The term 'long-term firm power service contract' means any contract for the sale by Western Area Power Administration of firm capacity, with or without energy, which is to be delivered over a period of more than one year.

"(5) The terms 'customer' or 'customers' means any entity or entities purchasing firm capacity with or without energy, from the Western Area Power Administration under a long-term firm power service contract. Such terms include parent-type entities and their distribution or user members.

"(6) For any customer, the term 'applicable integrated resource plan' means the integrated resource plan approved by the Administrator under this title for that customer.

"SEC. 202. REGULATIONS TO REQUIRE INTEGRATED RESOURCE PLANNING.

"(a) REGULATIONS.—Within 1 year after the enactment of this section, the Administrator shall, by regulation, revise the Final Amended Guidelines and Acceptance Criteria for Customer Conservation and Renewable Energy Programs published in the Federal Register on August 21, 1985 (50 F.R. 33892), or any subsequent amendments thereto, to require each customer purchasing electric energy under a long-term firm power service contract with the Western Area Power Administration to implement, within 3 years after the enactment of this section, integrated resource planning in accordance with the requirements of this title.

"(b) CERTAIN SMALL CUSTOMERS.—Notwithstanding subsection (a), for customers with total annual energy sales or usage of 25 Gigawatt Hours or less which are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility, the Administrator may establish different regulations and apply such regulations to customers that the Administrator finds have limited economic, managerial, and resource capability to conduct integrated resource planning. The regulations

under this subsection shall require such customers to consider a reasonable opportunities to meet their future energy service requi ments using demand-side techniques, new renewable resources ar other programs that will provide retail customers with electricity the lowest possible cost, and minimize, to the extent practicable, a verse environmental effects.

"SEC. 203. TECHNICAL ASSISTANCE.

"The Administrator may provide technical assistance to cu tomers to, among other things, conduct integrated resource pla ning, implement applicable integrated resource plans, and otherwis comply with the requirements of this title. Technical assistance ma include publications, workshops, conferences, one-to-one assistanc equipment loans, technology and resource assessment studies, ma keting studies, and other mechanisms to transfer information o energy efficiency and renewable energy options and programs to cus tomers. The Administrator shall give priority to providing technica assistance to customers that have limited capability to conduct inte grated resource planning.

"SEC. 204. INTEGRATED RESOURCE PLANS.

"(a) REVIEW BY WESTERN AREA POWER ADMINISTRATION.—Within 1 year after the enactment of this section, the Administrato shall, by regulation, revise the Final Amended Guidelines and Ac ceptance Criteria for Customer Conservation and Renewable Energ Programs published in the Federal Register on August 21, 1985 (5C F.R. 33892), or any subsequent amendments thereto, to require each customer to submit an integrated resource plan to the Administrator within 12 months after such regulations are amended. The regulation shall require a revision of such plan to be submitted every 5 years after the initial submission. The Administrator shall review the initial plan in accordance with a schedule established by the Administrator (which schedule will provide for the review of all initial plans within 24 months after such regulations are amended), and each revision thereof within 120 days after his receipt of the plan or revision and determine whether the customer has in the development of the plan or revision, complied with this title. Plan amendments may be submitted to the Administrator at any time and the Administrator shall review each such amendment within 120 days after receipt thereof to determine whether the customer in amending its plan has complied with this title. If the Administrator determines that the customer, in developing its plan, revision, or amendment, has not complied with the requirements of this title, the customer shall resubmit the plan at any time thereafter. Whenever a plan or revision or amendment is resubmitted the Administrator shall review the plan or revision or amendment within 120 days after his receipt thereof to determine whether the customer has complied with this title.

"(b) CRITERIA FOR APPROVAL OF INTEGRATED RESOURCE PLANS.—The Administrator shall approve an integrated resource plan submitted as required under subsection (a) if, in developing the plan, the customer has:

"(1) Identified and accurately compared all practicable energy efficiency and energy supply resource options available to the customer.

"(2) Included a 2-year action plan and a 5-year action plan which describe specific actions the customer will take to implement its integrated resource plan.

"(3) Designated 'least-cost options' to be utilized by the customer for the purpose of providing reliable electric service to its retail consumers and explained the reasons why such options were selected.

"(4) To the extent practicable, minimized adverse environmental effects of new resource acquisitions.

"(5) In preparation and development of the plan (and each revision or amendment of the plan) has provided for full public participation, including participation by governing boards.

"(6) Included load forecasting.

"(7) Provided methods of validating predicted performance in order to determine whether objectives in the plan are being met.

"(8) Met such other criteria as the Administrator shall require.

"(c) USE OF OTHER INTEGRATED RESOURCE PLANS.—Where a customer or group of customers are implementing integrated resource planning under a program responding to Federal, State, or other initiatives, including integrated resource planning considered and implemented pursuant to section 111(d) of the Public Utility Regulatory Policies Act of 1978, in evaluating that customer's integrated resource plan under this title, the Administrator shall accept such plan as fulfillment of the requirements of this title to the extent such plan substantially complies with the requirements of this title.

"(d) COMPLIANCE WITH INTEGRATED RESOURCE PLANS.—Within 1 year after the enactment of this section, the Administrator shall, by regulation, revise the Final Amended Guidelines and Acceptance Criteria for Customer Conservation and Renewable Energy Programs published in the Federal Register on August 21, 1985 (50 F.R. 33892), or any subsequent amendments thereto, to require each customer to fully comply with the applicable integrated resource plan and submit an annual report to the Administrator (in such form and containing such information as the Administrator may require) describing the customer's progress to the goals established in such plan. After the initial review under subsection (a) the Administrator shall periodically conduct reviews of a representative sample of applicable integrated resource plans and the customer's implementation of the applicable integrated resource plan to determine if the customers are in compliance with their plans. If the Administrator finds a customer out-of-compliance, the Administrator shall impose a surcharge under this section on all electric energy purchased by the customer from the Western Area Power Administration or reduce such customer's power allocation by 10 percent, unless the Administrator finds that a good faith effort has been made to comply with the approved plan.

"(e) ENFORCEMENT.—

"(1) NO APPROVED PLAN.—If an integrated resource plan for any customer is not submitted before the date 12 months after the guidelines are amended as required under this section or if the plan is disapproved by the Administrator and a revised

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plan is not resubmitted by the date 9 months after the date of such disapproval, the Administrator shall impose a surcharge of 10 percent of the purchase price on all power obtained by that customer from the Western Area Power Administration after such date. The surcharge shall remain in effect until an integrated resource plan is approved for that customer. If the plan is not submitted for more than one year after the required date, the surcharge shall increase to 20 percent for the second year (or any portion thereof prior to approval of the plan) and to 30 percent thereafter until the plan is submitted or the contract for the purchase of power by such customer from the Western Area Power Administration terminates.

"(2) FAILURE TO COMPLY WITH APPROVED PLAN.—After approval by the Administrator of an applicable integrated resource plan for any customer, the Administrator shall impose a 10 percent surcharge on all power purchased by such customer from the Western Area Power Administration whenever the Administrator determines that such customer's activities are not consistent with the applicable integrated resource plan. The surcharge shall remain in effect until the Administrator determines that the customer's activities are consistent with the applicable integrated resource plan. The surcharge shall be increased to 20 percent if the customer's activities are out of compliance for more than one year and to 30 percent after more than 2 years, except that no surcharge shall be imposed if the customer demonstrates, to the satisfaction of the Administrator, that a good faith effort has been made to comply with the approved plan.

"(3) REDUCTION IN POWER ALLOCATION.—In the case of any customer subject to a surcharge under paragraph (1) or (2), in lieu of imposing such surcharge the Administrator may reduce such customer's power allocation from the Western Area Power Administration by 10 percent. The Administrator shall provide by regulation the terms and conditions under which a power allocation terminated under this subsection may be reinstated.

"(f) INTEGRATED RESOURCE PLANNING COOPERATIVES.—With the approval of the Administrator, customers within any State or region may form integrated resource planning cooperatives for the purposes of complying with this title, and such customers shall be allowed an additional 6 months to submit an initial integrated resource plan to the Administrator.

"(g) CUSTOMERS WITH MORE THAN 1 CONTRACT.—If more than one long-term firm power service contract exists between the Administrator and a customer, only one integrated resource plan shall be required for that customer under this title.

"(h) PROGRAM REVIEW.—Within 1 year after January 1, 1999, and at appropriate intervals thereafter, the Administrator shall initiate a public process to review the program established by this section. The Administrator is authorized at that time to revise the criteria set forth in section 204(b) to reflect changes, if any, in technology, needs, or other developments.

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"SEC. 205. MISCELLANEOUS PROVISIONS.

"(a) ENVIRONMENTAL IMPACT STATEMENT.—The provisions of the National Environmental Policy Act of 1969 shall apply to actions of the Administrator implementing this title in the same manner and to the same extent as such provisions apply to other major Federal actions significantly affecting the quality of the human environment.

"(b) ANNUAL REPORTS.—The Administrator shall include in the annual report submitted by the Western Area Power Administration (1) a description of the activities undertaken by the Administrator and by customers under this title and (2) an estimate of the energy savings and renewable resource benefits achieved as a result of such activities.

"(c) STATE REGULATED INVESTOR-OWNED UTILITIES.—Any State regulated electric utility (as defined in section 3(18) of the Public Utility Regulatory Policies Act of 1978) shall be exempt from the provisions of this title.

"(d) RURAL ELECTRIFICATION ADMINISTRATION REQUIREMENTS.—Nothing in this title shall require a customer to take any action inconsistent with a requirement imposed by the Rural Electrification Administration".

SEC. 115. ENCOURAGEMENT OF INVESTMENTS IN CONSERVATION AND ENERGY EFFICIENCY BY GAS UTILITIES.

(a) DEFINITIONS.—Section 302 of the Public Utility Regulatory Policies Act of 1978 (15 U.S.C. 3202) is amended by adding the following at the end thereof:

"(9) The term 'integrated resource planning' means, in the case of a gas utility, planning by the use of any standard, regulation, practice, or policy to undertake a systematic comparison between demand-side management measures and the supply of gas by a gas utility to minimize life-cycle costs of adequate and reliable utility services to gas consumers. Integrated resource planning shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to gas consumers on a consistent and integrated basis.

"(10) The term 'demand-side management' includes energy conservation, energy efficiency, and load management techniques.".

(b) IN GENERAL.—Section 303(b) of the Public Utility Regulatory Policies Act of 1978 (15 U.S.C. 3202) is amended by inserting at the end the following new paragraphs:

"(3) INTEGRATED RESOURCE PLANNING.—Each gas utility shall employ, in order to provide adequate and reliable service to its gas customers at the lowest system cost. All plans or filings of a State regulated gas utility before a State regulatory authority to meet the requirements of this paragraph shall (A) be updated on a regular basis, (B) provide the opportunity for public participation and comment, (C) provide for methods of validating predicted performance, and (D) contain a requirement that the plan be implemented after approval of the State regulatory authority. Subsection (c) shall not apply to this paragraph to the extent that it could be construed to require the

State regulatory authority to extend the record of a State proceeding in submitting reports to the Federal Government.

"(4) INVESTMENTS IN CONSERVATION AND DEMAND MANAGEMENT.—The rates charged by any State regulated gas utility shall be such that the utility's prudent investments in, and expenditures for, energy conservation and load shifting programs and for other demand-side management measures which are consistent with the findings and purposes of the Energy Policy Act of 1992 are at least as profitable (taking into account the income lost due to reduced sales resulting from such programs) as prudent investments in, and expenditures for, the acquisition or construction of supplies and facilities. This objective requires that (A) regulators link the utility's net revenues, at least in part, to the utility's performance in implementing cost-effective programs promoted by this section; and (B) regulators ensure that, for purposes of recovering fixed costs, including its authorized return, the utility's performance is not affected by reductions in its retail sales volumes.".

(c) IMPACT ON SMALL BUSINESS.—Section 303 of such Act is amended by inserting the following new subsection at the end thereof:

"(d) SMALL BUSINESS IMPACTS.—If a State regulatory authority implements a standard established by subsection (b) (3) or (4), such authority shall—

"(1) consider the impact that implementation of such standard would have on small businesses engaged in the design, sale, supply, installation, or servicing of energy conservation, energy efficiency, or other demand-side management measures, and

"(2) implement such standard so as to assure that utility actions would not provide such utilities with unfair competitive advantages over such small businesses.".

(d) EFFECTIVE DATE.—Section 303(a) of such Act is amended by inserting "(or after the enactment of the Energy Policy Act of 1992 in the case of standards under paragraphs (3), and (4) of subsection (b))" after "Act" and by striking out "standard established by subsection (b)(2)" in paragraph (2) and inserting "standards established by paragraphs (2), (3) and (4) of subsection (b)".

(e) REPORT.—The report under section 111(e) of this Act transmitted by the Secretary of Energy to the President and to the Congress shall contain a survey of all State laws, regulations, practices, and policies under which State regulatory authorities implement the provisions of paragraphs (3) and (4) of section 303(b) of the Public Utility Regulatory Policies Act of 1978. The report shall include an analysis, prepared in conjunction, with the Federal Trade Commission, of the competitive impact of implementation of energy conservation, energy efficiency, and other demand side management programs by gas utilities on small businesses engaged in the design, sale, supply, installation, or servicing of similar energy conservation, energy efficiency, or other demand-side management measures and whether any unfair, deceptive, or predatory acts or practices exist, or are likely to exist, from implementation of such programs.

United States - Federal

TAB 5

Energy Policy Act of 1992
Title VII (Electricity)
Subtitle A (Exempt Wholesale Generators)

SEC. 625. ELECTRIC UTILITY PARTICIPATION STUDY.

The Secretary, in consultation with appropriate Federal agencies, representatives of State regulatory commissions and electric utilities, and such other persons as the Secretary considers appropriate, shall undertake or cause to have undertaken a study to determine the means by which electric utilities may invest in, own, sell, lease, service, or recharge batteries used to power electric motor vehicles.

SEC. 626. AUTHORIZATION OF APPROPRIATIONS.

There are authorized to be appropriated to the Secretary for purposes of this subtitle $40,000,000 for the 5-year period beginning with the first full fiscal year after the date of enactment of this Act, to remain available until expended.

TITLE VII—ELECTRICITY

Subtitle A—Exempt Wholesale Generators

SEC. 711. PUBLIC UTILITY HOLDING COMPANY ACT REFORM.

The Public Utility Holding Company Act of 1935 (15 U.S.C. 79 and following) is amended by redesignating sections 32 and 33 as sections 34 and 35 respectively and by adding the following new section after section 31:

"SEC. 32. EXEMPT WHOLESALE GENERATORS.

"(a) DEFINITIONS.—For purposes of this section—

"(1) EXEMPT WHOLESALE GENERATOR.—The term 'exempt wholesale generator' means any person determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly through one or more affiliates as defined in section 2(a)(11)(B), and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale. No person shall be deemed to be an exempt wholesale generator under this section unless such person has applied to the Federal Energy Regulatory Commission for a determination under this paragraph. A person applying in good faith for such a determination shall be deemed an exempt wholesale generator under this section, with all of the exemptions provided by this section, until the Federal Energy Regulatory Commission makes such determination. The Federal Energy Regulatory Commission shall make such determination within 60 days of its receipt of such application and shall notify the Commission whenever a determination is made under this paragraph that any person is an exempt wholesale generator. Not later than 12 months after the date of enactment of this section, the Federal Energy Regulatory Commission shall promulgate rules implementing the provisions of this paragraph. Applications for determination filed after the effective date of such rules shall be subject thereto.

"(2) ELIGIBLE FACILITY.—The term 'eligible facility' means a facility, wherever located, which is either—

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"(A) used for the generation of electric energy exclusively for sale at wholesale, or

"(B) used for the generation of electric energy and leased to one or more public utility companies; Provided, That any such lease shall be treated as a sale of electric energy at wholesale for purposes of sections 205 and 206 of the Federal Power Act.

Such term shall not include any facility for which consent is required under subsection (c) if such consent has not been obtained. Such term includes interconnecting transmission facilities necessary to effect a sale of electric energy at wholesale. For purposes of this paragraph, the term 'facility' may include a portion of a facility subject to the limitations of subsection (d) and shall include a facility the construction of which has not been commenced or completed.

"(3) SALE OF ELECTRIC ENERGY AT WHOLESALE.—The term 'sale of electric energy at wholesale' shall have the same meaning as provided in section 201(d) of the Federal Power Act (16 U.S.C. 824(d)).

"(4) RETAIL RATES AND CHARGES.—The term 'retail rates and charges' means rates and charges for the sale of electric energy directly to consumers.

"(b) FOREIGN RETAIL SALES.—Notwithstanding paragraphs (1) and (2) of subsection (a), retail sales of electric energy produced by a facility located in a foreign country shall not prevent such facility from being an eligible facility, or prevent a person owning or operating, or both owning and operating, such facility from being an exempt wholesale generator if none of the electric energy generated by such facility is sold to consumers in the United States.

"(c) STATE CONSENT FOR EXISTING RATE-BASED FACILITIES.—If a rate or charge for, or in connection with, the construction of a facility, or for electric energy produced by a facility (other than any portion of a rate or charge which represents recovery of the cost of a wholesale rate or charge) was in effect under the laws of any State as of the date of enactment of this section, in order for the facility to be considered an eligible facility, every State commission having jurisdiction over any such rate or charge must make a specific determination that allowing such facility to be an eligible facility (1) will benefit consumers, (2) is in the public interest, and (3) does not violate State law; Provided, That in the case of such a rate or charge which is a rate or charge of an affiliate of a registered holding company:

"(A) such determination with respect to the facility in question shall be required from every State commission having jurisdiction over the retail rates and charges of the affiliates of such registered holding company; and

"(B) the approval of the Commission under this Act shall not be required for the transfer of the facility to an exempt wholesale generator.

"(d) HYBRIDS.—(1) No exempt wholesale generator may own or operate a portion of any facility if any other portion of the facility is owned or operated by an electric utility company that is an affiliate or associate company of such exempt wholesale generator.

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"(2) ELIGIBLE FACILITY.—Notwithstanding paragraph (1), an exempt wholesale generator may own or operate a portion of a facility identified in paragraph (1) if such portion has become an eligible facility as a result of the operation of subsection (c).

"(e) EXEMPTION OF EWGS.—An exempt wholesale generator shall not be considered an electric utility company under section 2(a)(3) of this Act and, whether or not a subsidiary company, an affiliate, or an associate company of a holding company, an exempt wholesale generator shall be exempt from all provisions of this Act.

"(f) OWNERSHIP OF EWGS BY EXEMPT HOLDING COMPANIES.—Notwithstanding any provision of this Act, a holding company that is exempt under section 3 of this Act shall be permitted, without condition or limitation under this Act, to acquire and maintain an interest in the business of one or more exempt wholesale generators.

"(g) OWNERSHIP OF EWGS BY REGISTERED HOLDING COMPANIES.—Notwithstanding any provision of this Act and the Commission's jurisdiction as provided under subsection (h) of this section, a registered holding company shall be permitted (without the need to apply for, or receive, approval from the Commission, and otherwise without condition under this Act) to acquire and hold the securities, or an interest in the business, of one or more exempt wholesale generators.

"(h) FINANCING AND OTHER RELATIONSHIPS BETWEEN EWGS AND REGISTERED HOLDING COMPANIES.—The issuance of securities by a registered holding company for purposes of financing the acquisition of an exempt wholesale generator, the guarantee of securities of an exempt wholesale generator by a registered holding company, the entering into service, sales or construction contracts, and the creation or maintenance of any other relationship in addition to that described in subsection (g) between an exempt wholesale generator and a registered holding company, its affiliates and associate companies, shall remain subject to the jurisdiction of the Commission under this Act: Provided, That—

"(1) section 11 of this Act shall not prohibit the ownership of an interest in the business of one or more exempt wholesale generators by a registered holding company (regardless of where facilities owned or operated by such exempt wholesale generators are located), and such ownership by a registered holding company shall be deemed consistent with the operation of an integrated public utility system;

"(2) the ownership of an interest in the business of one or more exempt wholesale generators by a registered holding company (regardless of where facilities owned or operated by such exempt wholesale generators are located) shall be considered as reasonably incidental, or economically necessary or appropriate, to the operations of an integrated public utility system;

"(3) in determining whether to approve (A) the issue or sale of a security by a registered holding company for purposes of financing the acquisition of an exempt wholesale generator, or (B) the guarantee of a security of an exempt wholesale generator by a registered holding company, the Commission shall not make a finding that such security is not reasonably adapted to the earning power of such company or to the security structure of such company and other companies in the same holding company system, or that the circumstances are such as to constitut the making of such guarantee an improper risk for such compa ny, unless the Commission first finds that the issue or sale o such security, or the making of the guarantee, would have (substantial adverse impact on the financial integrity of the reg istered holding company system;

"(4) in determining whether to approve (A) the issue or sal of a security by a registered holding company for purposes othe than the acquisition of an exempt wholesale generator, or (B other transactions by such registered holding company or by its subsidiaries other than with respect to exempt wholesale generators, the Commission shall not consider the effect of the capitalization or earnings of any subsidiary which is an exempt wholesale generator upon the registered holding company system, unless the approval of the issue or sale or other transaction, together with the effect of such capitalization and earnings, would have a substantial adverse impact on the financial integrity of the registered holding company system;

"(5) the Commission shall make its decision under paragraph (3) to approve or disapprove the issue or sale of a security or the guarantee of a security within 120 days of the filing of a declaration concerning such issue, sale or guaruntee; and

"(6) the Commission shall promulgate regulations with respect to the actions which would be considered, for purposes of this subsection, to have a substantial adverse impact on the financial integrity of the registered holding company system; such regulations shall ensure that the action has no adverse impact on any utility subsidiary or its customers, or on the ability of State commissions to protect such subsidiary or customers, and shall take into account the amount and type of capital invested in exempt wholesale generators, the ratio of such capital to the total capital invested in utility operations, the availability of books and records, and the financial and operating experience of the registered holding company and the exempt wholesale generator; the Commission shall promulgate such regulations within 6 months after the enactment of this section; after such 6-month period the Commission shall not approve any actions under paragraph (3), (4) or (5) except in accordance with such issued regulations.

"(i) APPLICATION OF ACT TO OTHER ELIGIBLE FACILITIES.—In the case of any person engaged directly and exclusively in the business of owning or operating (or both owning and operating) all or part of one or more eligible facilities, an advisory letter issued by the Commission staff under this Act after the date of enactment of this section, or an order issued by the Commission under this Act after the date of enactment of this section, shall not be required for the purpose, or have the effect, of exempting such person from treatment as an electric utility company under section 2(a)(3) or exempting such person from any provision of this Act.

"(j) OWNERSHIP OF EXEMPT WHOLESALE GENERATORS AND QUALIFYING FACILITIES.—The ownership by a person of one or more exempt wholesale generators shall not result in such person being considered as being primarily engaged in the generation or sale of electric power within the meaning of sections 3(17)(C)(ii) and

3(18)(B)(ii) of the Federal Power Act (16 U.S.C. 796 (17)(C)(ii) and 796(18)(B)(ii)).

"(k) PROTECTION AGAINST ABUSIVE AFFILIATE TRANSACTIONS.—

"(1) PROHIBITION.—After the date of enactment of this section, an electric utility company may not enter into a contract to purchase electric energy at wholesale from an exempt wholesale generator if the exempt wholesale generator is an affiliate or associate company of the electric utility company.

"(2) STATE AUTHORITY TO EXEMPT FROM PROHIBITION.—Notwithstanding paragraph (1), an electric utility company may enter into a contract to purchase electric energy at wholesale from an exempt wholesale generator that is an affiliate or associate company of the electric utility company—

"(A) if every State commission having jurisdiction over the retail rates of such electric utility company makes each of the following specific determinations in advance of the electric utility company entering into such contract:

"(i) A determination that such commission has sufficient regulatory authority, resources and access to books and records of the electric utility company and any relevant associate, affiliate or subsidiary company to exercise its duties under this subparagraph.

"(ii) A determination that the transaction—

"(I) will benefit consumers,

"(II) does not violate any State law (including where applicable, least cost planning),

"(III) would not provide the exempt wholesale generator any unfair competitive advantage by virtue of its affiliation or association with the electric utility company, and

"(IV) is in the public interest; or

"(B) if such electric utility company is not subject to State commission retail rate regulation and the purchased electric energy:

"(i) would not be resold to any affiliate or associate company, or

"(ii) the purchased electric energy would be resold to an affiliate or associate company and every State commission having jurisdiction over the retail rates of such affiliate or associate company makes each of the determinations provided under subparagraph (A), including the determination concerning a State commission's duties.

"(l) RECIPROCAL ARRANGEMENTS PROHIBITED.—Reciprocal arrangements among companies that are not affiliates or associate companies of each other that are entered into in order to avoid the provisions of this section are prohibited.".

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SEC. 712. STATE CONSIDERATION OF THE EFFECTS OF POWER PURCHASES ON UTILITY COST OF CAPITAL; CONSIDERATION OF THE EFFECTS OF LEVERAGED CAPITAL STRUCTURES ON THE RELIABILITY OF WHOLESALE POWER SELLERS; AND CONSIDERATION OF ADEQUATE FUEL SUPPLIES.

Section 111 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 and following) is amended by inserting the following new paragraph after paragraph (9):

"(10) CONSIDERATION OF THE EFFECTS OF WHOLESALE POWER PURCHASES ON UTILITY COST OF CAPITAL; EFFECTS OF LEVERAGED CAPITAL STRUCTURES ON THE RELIABILITY OF WHOLESALE POWER SELLERS; AND ASSURANCE OF ADEQUATE FUEL SUPPLIES.—(A) To the extent that a State regulatory authority requires or allows electric utilities for which it has ratemaking authority to consider the purchase of long-term wholesale power supplies as a means of meeting electric demand, such authority shall perform a general evaluation of:

"(i) the potential for increases or decreases in the costs of capital for such utilities, and any resulting increases or decreases in the retail rates paid by electric consumers, that may result from purchases of long-term wholesale power supplies in lieu of the construction of new generation facilities by such utilities;

"(ii) whether the use by exempt wholesale generators (as defined in section 32 of the Public Utility Holding Company Act of 1935) of capital structures which employ proportionally greater amounts of debt than the capital structures of such utilities threatens reliability or provides an unfair advantage for exempt wholesale generators over such utilities;

"(iii) whether to implement procedures for the advance approval or disapproval of the purchase of a particular long-term wholesale power supply; and

"(iv) whether to require as a condition for the approval of the purchase of power that there be reasonable assurances of fuel supply adequacy.

"(B) For purposes of implementing the provisions of this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

"(C) Notwithstanding any other provision of Federal law, nothing in this paragraph shall prevent a State regulatory authority from taking such action, including action with respect to the allowable capital structure of exempt wholesale generators, as such State regulatory authority may determine to be in the public interest as a result of performing evaluations under the standards of subparagraph (A).

"(D) Notwithstanding section 124 and paragraphs (1) and (2) of section 112(a), each State regulatory authority shall consider and make a determination concerning the standards of subparagraph (A) in accordance with the requirements of subsections (a) and (b) of this section, without regard to any proceedings commenced prior to the enactment of this paragraph.

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"(E) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall consider and make a determination concerning whether it is appropriate to implement the standards set out in subparagraph (A) not later than one year after the date of enactment of this paragraph.".

SEC. 713. PUBLIC UTILITY HOLDING COMPANIES TO OWN INTERESTS IN COGENERATION FACILITIES.

Public Law 99-186 (99 Stat. 1180, as amended by Public Law 99-553, 100 Stat. 3087), is amended to read as follows:

"SECTION 1. Notwithstanding section 11(b)(1) of the Public Utility Holding Company Act of 1935, a company registered under said Act, or a subsidiary company of such registered company, may acquire or retain, in any geographic area, an interest in any qualifying cogeneration facilities and qualifying small power production facilities as defined pursuant to the Public Utility Regulatory Policies Act of 1978, and shall qualify for any exemption relating to the Public Utility Holding Company Act of 1935 prescribed pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978.

"SEC. 2. Nothing herein shall be construed to affect the applicability of section 3(17)(C) or section 3(18)(B) of the Federal Power Act or any provision of the Public Utility Holding Company Act of 1935, other than section 11(b)(1), to the acquisition or retention of any such interest by any such company.".

SEC. 714. BOOKS AND RECORDS.

Section 201 of the Federal Power Act is amended by adding the following new subsection at the end thereof:

"(g) BOOKS AND RECORDS.—(1) Upon written order of a State commission, a State commission may examine the books, accounts, memoranda, contracts, and records of—

"(A) an electric utility company subject to its regulatory authority under State law,

"(B) any exempt wholesale generator selling energy at wholesale to such electric utility, and

"(C) any electric utility company, or holding company thereof, which is an associate company or affiliate of an exempt wholesale generator which sells electric energy to an electric utility company referred to in subparagraph (A),

wherever located, if such examination is required for the effective discharge of the State commission's regulatory responsibilities affecting the provision of electric service.

"(2) Where a State commission issues an order pursuant to paragraph (1), the State commission shall not publicly disclose trade secrets or sensitive commercial information.

"(3) Any United States district court located in the State in which the State commission referred to in paragraph (1) is located shall have jurisdiction to enforce compliance with this subsection.

"(4) Nothing in this section shall—

"(A) preempt applicable State law concerning the provision of records and other information; or

"(B) in any way limit rights to obtain records and other information under Federal law, contracts, or otherwise.

"(5) As used in this subsection the terms 'affiliate', 'associate company', 'electric utility company', 'holding company', 'subsidiary

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company', and 'exempt wholesale generator' shall have the same meaning as when used in the Public Utility Holding Company Act of 1935.".

SEC. 715. INVESTMENT IN FOREIGN UTILITIES.

The Public Utility Holding Company Act of 1935 (15 U.S.C. 79 et seq.) is amended by inserting after section 32 the following new section:

"SEC. 33. TREATMENT OF FOREIGN UTILITIES.

"(a) EXEMPTIONS FOR FOREIGN UTILITY COMPANIES.—

"(1) IN GENERAL.—A foreign utility company shall be exempt from all of the provisions of this Act, except as otherwise provided under this section, and shall not, for any purpose under this Act, be deemed to be a public utility company under section 2(a)(5), notwithstanding that the foreign utility company may be a subsidiary company, an affiliate, or an associate company of a holding company or of a public utility company.

"(2) STATE COMMISSION CERTIFICATION.—Section (a)(1) shall not apply or be effective unless every State commission having jurisdiction over the retail electric or gas rates of a public utility company that is an associate company or an affiliate of a company otherwise exempted under section (a)(1) (other than a public utility company that is an associate company or an affiliate of a registered holding company) has certified to the Commission that it has the authority and resources to protect ratepayers subject to its jurisdiction and that it intends to exercise its authority. Such certification, upon the filing of a notice by such State commission, may be revised or withdrawn by the State commission prospectively as to any future acquisition. The requirement of State certification shall be deemed satisfied if the relevant State commission had, prior to the date of enactment of this section, on the basis of prescribed conditions of general applicability, determined that ratepayers of a public utility company are adequately insulated from the effects of diversification and the diversification would not impair the ability of the State commission to regulate effectively the operations of such company.

"(3) DEFINITION.—For purposes of this section, the term 'foreign utility company' means any company that—

"(A) owns or operates facilities that are not located in any State and that are used for the generation, transmission, or distribution of electric energy for sale or the distribution at retail of natural or manufactured gas for heat, light, or power, if such company—

"(i) derives no part of its income, directly or indirectly, from the generation, transmission, or distribution of electric energy for sale or the distribution at retail of natural or manufactured gas for heat, light, or power, within the United States; and

"(ii) neither the company nor any of its subsidiary companies is a public utility company operating in the United States; and

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"(B) provides notice to the Commission, in such form as the Commission may prescribe, that such company is a foreign utility company.

"(b) OWNERSHIP OF FOREIGN UTILITY COMPANIES BY EXEMPT HOLDING COMPANIES.—Notwithstanding any provision of this Act except as provided under this section, a holding company that is exempt under section 3 of the Act shall be permitted without condition or limitation under the Act to acquire and maintain an interest in the business of one or more foreign utility companies.

"(c) REGISTERED HOLDING COMPANIES.—

"(1) OWNERSHIP OF FOREIGN UTILITY COMPANIES BY REGISTERED HOLDING COMPANIES.—Notwithstanding any provision of this Act except as otherwise provided under this section, a registered holding company shall be permitted as of the date of enactment of this section (without the need to apply for, or receive approval from the Commission) to acquire and hold the securities or an interest in the business, of one or more foreign utility companies. The Commission shall promulgate rules or regulations regarding registered holding companies' acquisition of interests in foreign utility companies which shall provide for the protection of the customers of a public utility company which is an associate company of a foreign utility company and the maintenance of the financial integrity of the registered holding company system.

"(2) ISSUANCE OF SECURITIES.—The issuance of securities by a registered holding company for purposes of financing the acquisition of a foreign utility company, the guarantee of securities of a foreign utility company by a registered holding company, the entering into service, sales, or construction contracts, and the creation or maintenance of any other relationship between a foreign utility company and a registered holding company, its affiliates and associate companies, shall remain subject to the jurisdiction of the Commission under this Act (unless otherwise exempted under this Act, in the case of a transaction with an affiliate or associate company located outside of the United States). Any State commission with jurisdiction over the retail rates of a public utility company which is part of a registered holding company system may make such recommendations to the Commission regarding the registered holding company's relationship to a foreign utility company, and the Commission shall reasonably and fully consider such State recommendation.

"(3) CONSTRUCTION.—Any interest in the business of 1 or more foreign utility companies, or 1 or more companies organized exclusively to own, directly or indirectly, the securities or other interest in a foreign utility company, shall for all purposes of this Act, be considered to be—

"(A) consistent with the operation of a single integrated public utility system, within the meaning of section 11; and

"(B) reasonably incidental, or economically necessary or appropriate, to the operations of an integrated public utility system, within the meaning of section 11.

"(d) EFFECT ON EXISTING LAW; NO STATE PREEMPTION.—Nothing in this section shall—

"(1) preclude any person from qualifying for or maintaining any exemption otherwise provided for under this Act or the rules, regulations, or orders promulgated or issued under this Act; or

"(2) be deemed or construed to limit the authority of any State (including any State regulatory authority) with respect to—

"(A) any public utility company or holding company subject to such State's jurisdiction; or

"(B) any transaction between any foreign utility company (or any affiliate or associate company thereof) and any public utility company or holding company subject to such State's jurisdiction.

(e) REPORTING REQUIREMENTS.—

"(1) FILING OF REPORTS.—A public utility company that is an associate company of a foreign utility company shall file with the Commission such reports (with respect to such foreign utility company) as the Commission may by rules, regulations, or order prescribe as necessary or appropriate in the public interest or for the protection of investors or consumers.

"(2) NOTICE OF ACQUISITIONS.—Not later than 30 days after the consummation of the acquisition of an interest in a foreign utility company by an associate company of a public utility company that is subject to the jurisdiction of a State commission with respect to its retail electric or gas rates or by such public utility company, such associate company or such public utility company, shall provide notice of such acquisition to every State commission having jurisdiction over the retail electric or gas rates of such public utility company, in such form as may be prescribed by the State commission.

"(f) PROHIBITION ON ASSUMPTION OF LIABILITIES.—

"(1) IN GENERAL.—No public utility company that is subject to the jurisdiction of a State commission with respect to its retail electric or gas rates shall issue any security for the purpose of financing the acquisition, or for the purposes of financing the ownership or operation, of a foreign utility company, nor shall any such public utility company assume any obligation or liability as guarantor, endorser, surety, or otherwise in respect of any security of a foreign utility company.

"(2) EXCEPTION FOR HOLDING COMPANIES WHICH ARE PREDOMINANTLY PUBLIC UTILITY COMPANIES.—Subsection (f)(1) shall not apply if:

"(A) the public utility company that is subject to the jurisdiction of a State commission with respect to its retail electric or gas rates is a holding company and is not an affiliate under section 2(a)(11)(B) of another holding company or is not subject to regulation as a holding company and has no affiliate as defined in section 2(a)(11)(A) that is a public utility company subject to the jurisdiction of a State commission with respect to its retail electric or gas rates; and

"(B) each State commission having jurisdiction with respect to the retail electric and gas rates of such public utility company expressly permits such public utility to

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engage in a transaction otherwise prohibited under section (f)(1); and

"(C) the transaction (aggregated with all other then-outstanding transactions exempted under this subsection) does not exceed 5 per centum of the then-outstanding total capitalization of the public utility.

"(g) PROHIBITION ON PLEDGING OR ENCUMBERING UTILITY ASSETS.—No public utility company that is subject to the jurisdiction of a State commission with respect to its retail electric or gas rates shall pledge or encumber any utility assets or utility assets of any subsidiary thereof for the benefit of an associate foreign utility company.".

Subtitle B—Federal Power Act; Interstate Commerce in Electricity

SEC. 721. AMENDMENTS TO SECTION 211 OF FEDERAL POWER ACT.

Section 211 of the Federal Power Act (16 U.S.C. 824j) is amended as follows:

(1) The first sentence of subsection (a) is amended to read as follows: "Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant.".

(2) In the second sentence of subsection (a), strike "the Commission may" and all that follows and insert "the Commission may issue such order if it finds that such order meets the requirements of section 212, and would otherwise be in the public interest. No order may be issued under this subsection unless the applicant has made a request for transmission services to the transmitting utility that would be the subject of such order at least 60 days prior to its filing of an application for such order.".

(3) Amend subsection (b) to read as follows:

"(b) RELIABILITY OF ELECTRIC SERVICE.—No order may be issued under this section or section 210 if, after giving consideration to consistently applied regional or national reliability standards, guidelines, or criteria, the Commission finds that such order would unreasonably impair the continued reliability of electric systems affected by the order.".

(4) In subsection (c)—

(A) Strike out paragraph (1).

(B) In paragraph (2) strike "which requires the electric" and insert "which requires the transmitting".

(C) Strike out paragraphs (3) and (4).

(5) In subsection (d)—

(A) In the first sentence of paragraph (1), strike "electric" and insert "transmitting" in each place it appears.

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(B) In the second sentence of paragraph (1) before "and each affected electric utility," insert "each affected transmitting utility,".

(C) In paragraph (3), strike "electric" and insert "transmitting".

(D) Strike the period in subparagraph (B) of paragraph (1) and insert "; or" and after subparagraph (B) insert the following new subparagraph:

"(C) the ordered transmission services require enlargement of transmission capacity and the transmitting utility subject to the order has failed, after making a good faith effort, to obtain the necessary approvals or property rights under applicable Federal, State, and local laws.".

SEC. 722. TRANSMISSION SERVICES.

Section 212 of the Federal Power Act is amended as follows:

(1) Strike subsections (a) and (b) and insert the following:

"(a) RATES, CHARGES, TERMS, AND CONDITIONS FOR WHOLESALE TRANSMISSION SERVICES.—An order under section 211 shall require the transmitting utility subject to the order to provide wholesale transmission services at rates, charges, terms, and conditions which permit the recovery by such utility of all the costs incurred in connection with the transmission services and necessary associated services, including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities. Such rates, charges, terms, and conditions shall promote the economically efficient transmission and generation of electricity and shall be just and reasonable, and not unduly discriminatory or preferential. Rates, charges, terms, and conditions for transmission services provided pursuant to an order under section 211 shall ensure that, to the extent practicable, costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for such order and not from a transmitting utility's existing wholesale, retail, and transmission customers.".

(2) Subsection (e) is amended to read as follows:

"(e) SAVINGS PROVISIONS.—(1) No provision of section 210, 211, 214, or this section shall be treated as requiring any person to utilize the authority of any such section in lieu of any other authority of law. Except as provided in section 210, 211, 214, or this section, such sections shall not be construed as limiting or impairing any authority of the Commission under any other provision of law.

"(2) Sections 210, 211, 213, 214, and this section, shall not be construed to modify, impair, or supersede the antitrust laws. For purposes of this section, the term 'antitrust laws' has the meaning given in subsection (a) of the first sentence of the Clayton Act, except that such term includes section 5 of the Federal Trade Commission Act to the extent that such section relates to unfair methods of competition.".

(3) Add the following new subsections at the end thereof:

"(g) PROHIBITION ON ORDERS INCONSISTENT WITH RETAIL MARKETING AREAS.—No order may be issued under this Act which is in-

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consistent with any State law which governs the retail marketing areas of electric utilities.

"(h) PROHIBITION ON MANDATORY RETAIL WHEELING AND SHAM WHOLESALE TRANSACTIONS.—*No order issued under this Act shall be conditioned upon or require the transmission of electric energy:*

"(1) *directly to an ultimate consumer, or*

"(2) *to, or for the benefit of, an entity if such electric energy would be sold by such entity directly to an ultimate consumer, unless:*

"(A) *such entity is a Federal power marketing agency; the Tennessee Valley Authority; a State or any political subdivision of a State (or an agency, authority, or instrumentality of a State or a political subdivision); a corporation or association that has ever received a loan for the purposes of providing electric service from the Administrator of the Rural Electrification Administration under the Rural Electrification Act of 1936; a person having an obligation arising under State or local law (exclusive of an obligation arising solely from a contract entered into by such person) to provide electric service to the public; or any corporation or association which is wholly owned, directly or indirectly, by any one or more of the foregoing; and*

"(B) *such entity was providing electric service to such ultimate consumer on the date of enactment of this subsection or would utilize transmission or distribution facilities that it owns or controls to deliver all such electric energy to such electric consumer.*

Nothing in this subsection shall affect any authority of any State or local government under State law concerning the transmission of electric energy directly to an ultimate consumer.".

"(i) LAWS APPLICABLE TO FEDERAL COLUMBIA RIVER TRANSMISSION SYSTEM.—(1) *The Commission shall have authority pursuant to section 210, section 211, this section, and section 213 to (A) order the Administrator of the Bonneville Power Administration to provide transmission service and (B) establish the terms and conditions of such service. In applying such sections to the Federal Columbia River Transmission System, the Commission shall assure that—*

"(i) *the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and*

"(ii) *the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 210, section 211, this section, or section 213, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.*

"(2) *Notwithstanding any other provision of this Act with respect to the procedures for the determination of terms and conditions for transmission service—*

"(A) *when the Administrator of the Bonneville Power Administration either (i) in response to a written request for specific transmission service terms and conditions does not offer the requested terms and conditions, or (ii) proposes to establish*

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terms and conditions of general applicability for transmission service on the Federal Columbia River Transmission System, then the Administrator may provide opportunity for a hearing and, in so doing, shall—

"(I) give notice in the Federal Register and state in such notice the written explanation of the reasons why the specific terms and conditions for transmission services are not being offered or are being proposed;

"(II) adhere to the procedural requirements of paragraphs (1) through (3) of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839(i)(1) through (3)), except that the hearing officer shall, unless the hearing officer becomes unavailable to the agency, make a recommended decision to the Administrator that states the hearing officer's findings and conclusions, and the reasons or basis thereof, on all material issues of fact, law, or discretion presented on the record; and

"(III) make a determination, setting forth the reasons for reaching any findings and conclusions which may differ from those of the hearing officer, based on the hearing record, consideration of the hearing officer's recommended decision, section 211 and this section, as amended by the Energy Policy Act of 1992, and the provisions of law as preserved in this section; and

"(B) if application is made to the Commission under section 211 for transmission service under terms and conditions different than those offered by the Administrator, or following the denial of a request for transmission service by the Administrator, and such application is filed within 60 days of the Administrator's final determination and in accordance with Commission procedures, the Commission shall—

"(i) in the event the Administrator has conducted a hearing as herein provided for (I) accord parties to the Administrator's hearing the opportunity to offer for the Commission record materials excluded by the Administrator from the hearing record, (II) accord such parties the opportunity to submit for the Commission record comments on appropriate terms and conditions, (III) afford those parties the opportunity for a hearing if and to the extent that the Commission finds the Administrator's hearing record to be inadequate to support a decision by the Commission, and (IV) establish terms and conditions for or deny transmission service based on the Administrator's hearing record, the Commission record, section 211 and this section, as amended by the Energy Policy Act of 1992, and the provisions of law as preserved in this section, or

"(ii) in the event the Administrator has not conducted a hearing as herein provided for, determine whether to issue an order for transmission service in accordance with section 211 and this section, including providing the opportunity for a hearing.

"(3) Notwithstanding those provisions of section 313(b) of this Act (16 U.S.C. 825l) which designate the court in which review may be obtained, any party to a proceeding concerning transmission serv-

ice sought to be furnished by the Administrator of the Bonneville Power Administration seeking review of an order issued by the Commission in such proceeding shall obtain a review of such order in the United States Court of Appeals for the Pacific Northwest, as that region is defined by section 3(14) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839a(14)).

"(4) To the extent the Administrator of the Bonneville Power Administration cannot be required under section 211, as a result of the Administrator's other statutory mandates, either to (A) provide transmission service to an applicant which the Commission would otherwise order, or (B) provide such service under rates, terms, and conditions which the Commission would otherwise require, the applicant shall not be required to provide similar transmission services to the Administrator or to provide such services under similar rates, terms, and conditions.

"(5) The Commission shall not issue any order under section 210, section 211, this section, or section 213 requiring the Administrator of the Bonneville Power Administration to provide transmission service if such an order would impair the Administrator's ability to provide such transmission service to the Administrator's power and transmission customers in the Pacific Northwest, as that region is defined in section 3(14) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839a(14)), as is needed to assure adequate and reliable service to loads in that region.

"(j) EQUITABILITY WITHIN TERRITORY RESTRICTED ELECTRIC SYSTEMS.—With respect to an electric utility which is prohibited by Federal law from being a source of power supply, either directly or through a distributor of its electric energy, outside an area set forth in such law, no order issued under section 211 may require such electric utility (or a distributor of such electric utility) to provide transmission services to another entity if the electric energy to be transmitted will be consumed within the area set forth in such Federal law, unless the order is in furtherance of a sale of electric energy to that electric utility: Provided, however, That the foregoing provision shall not apply to any area served at retail by an electric transmission system which was such a distributor on the date of enactment of this subsection and which before October 1, 1991, gave its notice of termination under its power supply contract with such electric utility.

"(k) ERCOT UTILITIES.—

"(1) RATES.—Any order under section 211 requiring provision of transmission services in whole or in part within ERCOT shall provide that any ERCOT utility which is not a public utility and the transmission facilities of which are actually used for such transmission service is entitled to receive compensation based, insofar as practicable and consistent with subsection (a), on the transmission ratemaking methodology used by the Public Utility Commission of Texas.

"(2) DEFINITIONS.—For purposes of this subsection—

"(A) the term 'ERCOT' means the Electric Reliability Council of Texas; and

"(B) the term 'ERCOT utility' means a transmitting utility which is a member of ERCOT.".

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SEC. 723. INFORMATION REQUIREMENTS.

Part II of the Federal Power Act is amended by adding the following new section after section 212:

"SEC. 213. INFORMATION REQUIREMENTS.

"(a) REQUESTS FOR WHOLESALE TRANSMISSION SERVICES.—Whenever any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale makes a good faith request to a transmitting utility to provide wholesale transmission services and requests specific rates and charges, and other terms and conditions, unless the transmitting utility agrees to provide such services at rates, charges, terms and conditions acceptable to such person, the transmitting utility shall, within 60 days of its receipt of the request, or other mutually agreed upon period, provide such person with a detailed written explanation, with specific reference to the facts and circumstances of the request, stating (1) the transmitting utility's basis for the proposed rates, charges, terms, and conditions for such services, and (2) its analysis of any physical or other constraints affecting the provision of such services.

"(b) TRANSMISSION CAPACITY AND CONSTRAINTS.—Not later than 1 year after the enactment of this section, the Commission shall promulgate a rule requiring that information be submitted annually to the Commission by transmitting utilities which is adequate to inform potential transmission customers, State regulatory authorities, and the public of potentially available transmission capacity and known constraints.".

SEC. 724. SALES BY EXEMPT WHOLESALE GENERATORS.

Part II of the Federal Power Act is amended by adding the following new section after section 213:

"SEC. 214. SALES BY EXEMPT WHOLESALE GENERATORS.

"No rate or charge received by an exempt wholesale generator for the sale of electric energy shall be lawful under section 205 if, after notice and opportunity for hearing, the Commission finds that such rate or charge results from the receipt of any undue preference or advantage from an electric utility which is an associate company or an affiliate of the exempt wholesale generator. For purposes of this section, the terms 'associate company' and 'affiliate' shall have the same meaning as provided in section 2(a) of the Public Utility Holding Company Act of 1935.".

SEC. 725. PENALTIES.

(a) EXISTING PENALTIES NOT APPLICABLE TO TRANSMISSION PROVISIONS.—Sections 315 and 316 of the Federal Power Act are each amended by adding the following at the end thereof:

"(c) This subsection shall not apply in the case of any provision of section 211, 212, 213, or 214 or any rule or order issued under any such provision.".

(b) PENALTIES APPLICABLE TO TRANSMISSION PROVISIONS.—Title III of the Federal Power Act is amended by inserting the following new section after section 316:

"SEC. 316A. ENFORCEMENT OF CERTAIN PROVISIONS.

"(a) VIOLATIONS.—It shall be unlawful for any person to violate any provision of section 211, 212, 213, or 214 or any rule or order issued under any such provision.

"(b) CIVIL PENALTIES.—Any person who violates any provision of section 211, 212, 213, or 214 or any provision of any rule or order thereunder shall be subject to a civil penalty of not more than $10,000 for each day that such violation continues. Such penalty shall be assessed by the Commission, after notice and opportunity for public hearing, in accordance with the same provisions as are applicable under section 31(d) in the case of civil penalties assessed under section 31. In determining the amount of a proposed penalty, the Commission shall take into consideration the seriousness of the violation and the efforts of such person to remedy the violation in a timely manner.".

SEC. 726. DEFINITIONS.

(a) ADDITIONAL DEFINITIONS.—Section 3 of the Federal Power Act is amended by adding the following at the end thereof:

"(23) TRANSMITTING UTILITY.—The term 'transmitting utility' means any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.

"(24) WHOLESALE TRANSMISSION SERVICES.—The term 'wholesale transmission services' means the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.

"(25) EXEMPT WHOLESALE GENERATOR.—The term 'exempt wholesale generator' shall have the meaning provided by section 32 of the Public Utility Holding Company Act of 1935.".

(b) CLARIFICATION OF TERMS.—Section 3(22) of the Federal Power Act is amended by inserting "(including any municipality)" after "State agency".

Subtitle C—State and Local Authorities

SEC. 731. STATE AUTHORITIES.

Nothing in this title or in any amendment made by this title shall be construed as affecting or intending to affect, or in any way to interfere with, the authority of any State or local government relating to environmental protection or the siting of facilities.

TITLE VIII—HIGH-LEVEL RADIOACTIVE WASTE

SEC. 801. NUCLEAR WASTE DISPOSAL.

(a) ENVIRONMENTAL PROTECTION AGENCY STANDARDS.—

(1) PROMULGATION.—Notwithstanding the provisions of section 121(a) of the Nuclear Waste Policy Act of 1982 (42 U.S.C. 10141(a)), section 161 b. of the Atomic Energy Act of 1954 (42 U.S.C. 2201(b)), and any other authority of the Administrator of the Environmental Protection Agency to set generally applicable standards for the Yucca Mountain site, the Administrator shall, based upon and consistent with the findings and recom-

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mendations of the National Academy of Sciences, promulgate, by rule, public health and safety standards for protection of the public from releases from radioactive materials stored or disposed of in the repository at the Yucca Mountain site. Such standards shall prescribe the maximum annual effective dose equivalent to individual members of the public from releases to the accessible environment from radioactive materials stored or disposed of in the repository. The standards shall be promulgated not later than 1 year after the Administrator receives the findings and recommendations of the National Academy of Sciences under paragraph (2) and shall be the only such standards applicable to the Yucca Mountain site.

(2) STUDY BY NATIONAL ACADEMY OF SCIENCES.—Within 90 days after the date of the enactment of this Act, the Administrator shall contract with the National Academy of Sciences to conduct a study to provide, by not later than December 31, 1993, findings and recommendations on reasonable standards for protection of the public health and safety, including—

(A) whether a health-based standard based upon doses to individual members of the public from releases to the accessible environment (as that term is defined in the regulations contained in subpart B of part 191 of title 40, Code of Federal Regulations, as in effect on November 18, 1985) will provide a reasonable standard for protection of the health and safety of the general public;

(B) whether it is reasonable to assume that a system for post-closure oversight of the repository can be developed, based upon active institutional controls, that will prevent an unreasonable risk of breaching the repository's engineered or geologic barriers or increasing the exposure of individual members of the public to radiation beyond allowable limits; and

(C) whether it is possible to make scientifically supportable predictions of the probability that the repository's engineered or geologic barriers will be breached as a result of human intrusion over a period of 10,000 years.

(3) APPLICABILITY.—The provisions of this section shall apply to the Yucca Mountain site, rather than any other authority of the Administrator to set generally applicable standards for radiation protection.

(b) NUCLEAR REGULATORY COMMISSION REQUIREMENTS AND CRITERIA.—

(1) MODIFICATIONS.—Not later than 1 year after the Administrator promulgates standards under subsection (a), the Nuclear Regulatory Commission shall, by rule, modify its technical requirements and criteria under section 121(b) of the Nuclear Waste Policy Act of 1982 (42 U.S.C. 10141(b)), as necessary, to be consistent with the Administrator's standards promulgated under subsection (a).

(2) REQUIRED ASSUMPTIONS.—The Commission's requirements and criteria shall assume, to the extent consistent with the findings and recommendations of the National Academy of Sciences, that, following repository closure, the inclusion of engineered barriers and the Secretary's post-closure oversight of

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the Yucca Mountain site, in accordance with subsection (c), shall be sufficient to—

(A) prevent any activity at the site that poses an unreasonable risk of breaching the repository's engineered or geologic barriers; and

(B) prevent any increase in the exposure of individual members of the public to radiation beyond allowable limits.

(c) POST-CLOSURE OVERSIGHT.—Following repository closure, the Secretary of Energy shall continue to oversee the Yucca Mountain site to prevent any activity at the site that poses an unreasonable risk of—

(1) breaching the repository's engineered or geologic barriers; or

(2) increasing the exposure of individual members of the public to radiation beyond allowable limits.

SEC. 802. OFFICE OF THE NUCLEAR WASTE NEGOTIATOR.

(a) EXTENSION.—Section 410 of the Nuclear Waste Policy Act of 1982 (42 U.S.C. 10250) is amended by striking "5 years" and inserting "7 years".

(b) DEFINITION OF STATE.—Section 401 of the Nuclear Waste Policy Act of 1982 (42 U.S.C. 10241) is amended—

(1) by striking "States," the first place it appears and inserting "States and"; and

(2) by inserting a period after "District of Columbia" and striking the remainder of the sentence.

SEC. 803. NUCLEAR WASTE MANAGEMENT PLAN.

(a) PREPARATION AND SUBMISSION OF REPORT.—The Secretary of Energy, in consultation with the Nuclear Regulatory Commission and the Environmental Protection Agency, shall prepare and submit to the Congress a report on whether current programs and plans for management of nuclear waste as mandated by the Nuclear Waste Policy Act of 1982 (42 U.S.C. 10101 et seq.) are adequate for management of any additional volumes or categories of nuclear waste that might be generated by any new nuclear power plants that might be constructed and licensed after the date of the enactment of this Act. The Secretary shall prepare the report for submission to the President and the Congress within 1 year after the date of the enactment of this Act. The report shall examine any new relevant issues related to management of spent nuclear fuel and high-level radioactive waste that might be raised by the addition of new nuclear-generated electric capacity, including anticipated increased volumes of spent nuclear fuel or high-level radioactive waste, any need for additional interim storage capacity prior to final disposal, transportation of additional volumes of waste, and any need for additional repositories for deep geologic disposal.

(b) OPPORTUNITY FOR PUBLIC COMMENT.—In preparation of the report required under subsection (a), the Secretary of Energy shall offer members of the public an opportunity to provide information and comment and shall solicit the views of the Nuclear Regulatory Commission, the Environmental Protection Agency, and other interested parties.

(c) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated such sums as may be necessary to carry out this section.

TITLE IX—UNITED STATES ENRICHMENT CORPORATION

SEC. 901. ESTABLISHMENT OF THE UNITED STATES ENRICHMENT CORPORATION.

The Atomic Energy Act of 1954 (42 U.S.C. 2011 et seq.) is amended by adding at the end the following new title:

"TITLE II—UNITED STATES ENRICHMENT CORPORATION

"CHAPTER 22—GENERAL PROVISIONS

"SEC. 1201. DEFINITIONS.

"For purposes of this title:

"(1) The term 'alternative technologies for uranium enrichment' means technologies to enrich uranium by methods other than the gaseous diffusion process.

"(2) The term 'AVLIS' means atomic vapor laser isotope separation technology.

"(3) The term 'Board' means the Board of Directors of the Corporation established under section 1304.

"(4) The term 'Corporation' means the United States Enrichment Corporation.

"(5) The term 'corrective actions' has the meaning given such term by the Administrator of the Environmental Protection Agency under section 3004(u) of the Solid Waste Disposal Act (42 U.S.C. 6924 (u)).

"(6) The term 'decontamination and decommissioning' means those activities, other than response actions or corrective actions, undertaken to decontaminate and decommission inactive uranium enrichment facilities that have residual radioactive or mixed radioactive and hazardous chemical contamination, including depleted tailings.

"(7) The term 'Department' means the Department of Energy.

"(8) The term 'highly enriched uranium' means uranium enriched to 20 percent or more of the uranium-235 isotope.

"(9) The term 'low-enriched uranium' means uranium enriched to less than 20 percent of the uranium-235 isotope.

"(10) The term 'releases' has the meaning given the term 'release' in section 101(22) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (42 U.S.C. 9601(22)).

"(11) The term 'remedial action' has the meaning given such term in section 101(24) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (42 U.S.C. 9601(24)).

"(12) The term 'response actions' has the meaning given the term 'response' in section 101(25) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (42 U.S.C. 9601(25)).

"(13) The term 'Secretary' means the Secretary of Energy.

"(14) The term 'uranium enrichment' means the separation of uranium of a given isotopic content into 2 components, 1 having a higher percentage of a fissile isotope and 1 having a lower percentage.

"SEC. 1202. PURPOSES.

"The Corporation is created for the following purposes:

"(1) To operate as a business enterprise on a profitable and efficient basis.

"(2) To maximize the long-term value of the Corporation to the Treasury of the United States.

"(3) To lease Department uranium enrichment facilities, as needed.

"(4) To acquire uranium for uranium enrichment, low-enriched uranium for resale, and highly enriched uranium for conversion into low-enriched uranium, as needed.

"(5) To market and sell its enriched uranium and uranium enrichment and related services to—

"(A) the Department for governmental purposes; and

"(B) domestic and foreign persons, as provided in section 1303(6).

"(6) To conduct research and development as required to meet business objectives for the purposes of identifying, evaluating, improving, and testing alternative technologies for uranium enrichment.

"(7) To conduct the business as a self-financing corporation and eliminate the need for Federal Government appropriations or sources of Federal financing other than those provided in this title.

"(8) To help maintain a reliable and economical domestic source of uranium enrichment services.

"(9) To comply with laws, and regulations promulgated thereunder, to protect the public health, safety, and the environment.

"(10) To continue at all times to meet the objectives of ensuring the Nation's common defense and security, including abiding by United States laws and policies concerning special nuclear materials and nonproliferation of atomic weapons and other nonpeaceful uses of atomic energy.

"(11) To take all other lawful actions in furtherance of these purposes.

"CHAPTER 23—ESTABLISHMENT, POWERS, AND ORGANIZATION OF CORPORATION

"SEC. 1301. ESTABLISHMENT OF THE CORPORATION.

"(a) IN GENERAL.—There is established a body corporate to be known as the United States Enrichment Corporation.

"(b) GOVERNMENT CORPORATION.—The Corporation shall be established as a wholly owned Government corporation subject to

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to the Congress on progress under this chapter. The 5th report submitted under this section shall contain recommendations of the Secretary for the reauthorization of the program and Fund under this title.".

SEC. 1102. LICENSING OF AVLIS.

The last sentence of section 11 v. of the Atomic Energy Act of 1954 (42 U.S.C. 2014(v)) is amended to read as follows: "Except with respect to the export of a uranium enrichment production facility or the construction and operation of a uranium enrichment production facility using Atomic Vapor Laser Isotope Separation technology, such term as used in chapters 10 and 16 shall not include any equipment or device (or important component part especially designed for such equipment or device) capable of separating the isotopes of uranium or enriching uranium in the isotope 235.".

SEC. 1103. TABLE OF CONTENTS.

The table of contents for title II of the Atomic Energy Act of 1954, as added by title IX of this Act, is amended by adding at the end the following:

TITLE XII—RENEWABLE ENERGY

SEC. 1201. PURPOSES.

The purposes of this title are to promote—

(1) increases in the production and utilization of energy from renewable energy resources;

(2) further advances of renewable energy technologies; and

(3) exports of United States renewable energy technologies and services.

SEC. 1202. DEMONSTRATION AND COMMERCIAL APPLICATION PROJECTS FOR RENEWABLE ENERGY AND ENERGY EFFICIENCY TECHNOLOGIES.

(a) DEMONSTRATION AND COMMERCIAL APPLICATION PROJECTS.—Section 6 of the Renewable Energy and Energy Efficiency Technology Competitiveness Act of 1989 (42 U.S.C. 12005) is amended to read as follows:

"SEC. 6. DEMONSTRATION AND COMMERCIAL APPLICATION PROJECTS.

"(a) PURPOSE.—The purpose of this section is to direct the Secretary to further the commercialization of renewable energy and energy efficiency technologies through a five-year program.

"(b) DEMONSTRATION AND COMMERCIAL APPLICATION PROJECTS.—

"(1) ESTABLISHMENT.—(A) The Secretary shall solicit proposals for demonstration and commercial application projects for renewable energy and energy efficiency technologies pursuant to subsection (c). Such projects may include projects for—

"(i) the production and sale of electricity, thermal energy, or other forms of energy using a renewable energy technology;

"(ii) increasing the efficiency of energy use; and

"(iii) improvements in, or expansion of, facilities for the manufacture of renewable energy or energy efficiency technologies.

"(B) REQUIREMENTS.—Each project selected under this section shall include at least one for-profit business. Activities supported under this section shall be performed in the United States. Each project under this section shall require the manufacture and reproduction substantially within the United States for commercial sale of any invention or product that may result from the project.

"(2) FORMS OF FINANCIAL ASSISTANCE.—(A) In supporting projects selected under subsection (c), the Secretary may choose from among the forms of agreements described in section 3001 of the Energy Policy Act of 1992.

"(B) In supporting projects selected under subsection (c), the Secretary may also enter into agreements with private lenders to pay a portion of the interest on loans made for such projects.

"(3) COST SHARING.—Cost sharing for projects under this section shall be conducted according to the procedures described in section 3002(b) and (c) of the Energy Policy Act of 1992.

"(4) ADVISORY COMMITTEE.—(A) The Secretary shall establish an Advisory Committee on Demonstration and Commercial Application of Renewable Energy and Energy Efficiency Technologies (in this Act referred to as the 'Advisory Committee') to advise the Secretary on the development of the solicitation and evaluation criteria for projects under this section, and on otherwise carrying out his responsibilities under this section. The Secretary shall appoint members to the Advisory Committee, including at least one member representing—

"(i) the Secretary of Commerce;

"(ii) the National Laboratories of the Department of Energy;

"(iii) the Solar Energy Research Institute;

"(iv) the Electric Power Research Institute;

"(v) the Gas Research Institute;

"(vi) the National Institute of Building Sciences;

"(vii) the National Institute of Standards and Technology;

"(viii) associations of firms in the major renewable energy manufacturing industries; and

"(ix) associations of firms in the major energy efficiency manufacturing industries.

Nothing in this subparagraph shall be construed to require the Secretary to reestablish the Advisory Committee in place under this subsection as of the date of enactment of the Energy Policy

Act of 1992, or to perform again any duties performed by such advisory committee before such date of enactment.

"(B) Not later than 18 months after the date of the enactment of the Energy Policy Act of 1992, the Advisory Committee shall provide the Secretary with a report assessing the implementation of the program under this section, including specific recommendations for improvements or changes to the program and solicitation process. The Secretary shall transmit such report and, if any, the Secretary's recommendations to the Congress.

"(c) SELECTION OF PROJECTS.—

"(1) SOLICITATION.—(A) Not later than 9 months after the date of the enactment of the Energy Policy Act of 1992, the Secretary shall solicit proposals for projects under this section. The Secretary may make additional solicitations for proposals if the Secretary determines that such solicitations are necessary to carry out this section.

"(B) A solicitation for proposals under this paragraph shall establish a closing date for receipt of proposals. The Secretary may, if necessary, extend the closing date for receipt of proposals for a period not to exceed 90 days.

"(C) Each solicitation under this paragraph shall include a description of the criteria, developed by the Secretary, according to which proposals will be evaluated. In developing such criteria, the Secretary shall consider—

"(i) the need for Federal involvement to commercialize the technology or speed commercialization of the technology;

"(ii) the potential for the technology to have significant market penetration;

"(iii) the potential energy efficiency gains or energy supply contributions of the technology;

"(iv) potential environmental improvements associated with the technology;

"(v) the export potential of the technology;

"(vi) the likelihood that the proposal is technically sufficient to achieve the objective of the solicitation;

"(vii) the degree to which non-Federal financial participation is involved in the proposal;

"(viii) the business and financial history of the proposer or proposers; and

"(ix) any other factor the Secretary considers appropriate.

"(2) PROJECT TECHNOLOGIES.—Projects under this section may include the following technologies:

"(A) Conversion of cellulosic biomass to liquid fuels.

"(B) Ethanol and ethanol byproduct processes.

"(C) Direct combustion or gasification of biomass.

"(D) Biofuels energy systems.

"(E) Photovoltaics, including utility scale and remote applications.

"(F) Solar thermal, including solar water heating.

"(G) Wind energy.

"(H) High temperature and low temperature geothermal energy.

"(I) Fuel cells, including transportation and stationary applications.

"(J) Nondefense high-temperature superconducting electricity technology.

"(K) Source reduction technology.

"(L) Factory-made housing.

"(M) Advanced district cooling.

"(3) PROJECT SELECTION.—The Secretary shall, within 120 days after the closing date established under paragraph (1)(B), select proposals to receive financial assistance under this section. In selecting proposals under this paragraph, the Secretary shall—

"(A) consider each proposal's ability to meet the criteria developed pursuant to paragraph (1)(C); and

"(B) attempt to achieve technological and geographic diversity.

"(d) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary for carrying out this section $50,000,000 for fiscal year 1994.

(b) NATIONAL GOALS AND MULTIYEAR FUNDING FOR ALCOHOL FROM BIOMASS.—Section 4(a) of the Renewable Energy and Energy Efficiency Technology Competitiveness Act of 1989 (42 U.S.C. 12003(a)) is amended—

(1) by redesignating paragraph (4) as paragraph (5);

(2) by inserting after paragraph (3) the following new paragraph:

"(4) ALCOHOL FROM BIOMASS.—(A) In general, the goal of the Alcohol From Biomass Program shall be to advance research and development to a point where alcohol from biomass technology is cost-competitive with conventional hydrocarbon transportation fuels, and to promote the integration of this technology into the transportation fuel sector of the economy.

"(B)(i) Specific goals for producing ethanol from biomass shall be to—

"(I) reduce the cost of alcohol to 70 cents per gallon;

"(II) improve the overall biomass carbohydrate conversion efficiency to 91 percent;

"(III) reduce the capital cost component of the cost of alcohol to 23 cents per gallon; and

"(IV) reduce the operating and maintenance component of the cost of alcohol to 47 cents per gallon.

"(ii) Specific goals for producing methanol from biomass shall be to—

"(I) reduce the cost of alcohol to 47 cents per gallon; and

"(II) reduce the capital component of the cost of alcohol to 16 cents per gallon."; and

(3) in paragraph (5), as so redesignated by paragraph (1) of this subsection, by inserting "Biodiesel Energy Systems," after "Biofuels Energy Systems,".

(c) NATIONAL RENEWABLE ENERGY AND ENERGY EFFICIENCY MANAGEMENT PLAN.—Section 9(b) of the Renewable Energy and

Energy Efficiency Technology Competitiveness Act of 1989 (42 U.S.C. 12008(b)) is amended—

(1) in paragraph (1) by inserting "three-year" before "management plan"; and

(2) by striking paragraph (5) and inserting in lieu thereof the following new paragraphs:

"(5) In addition, the Plan shall—

"(A) contain a detailed assessment of program needs, objectives, and priorities for each of the programs authorized under section 6 of this Act;

"(B) use a uniform prioritization methodology to facilitate cost-benefit analyses of proposals in various program areas;

"(C) establish milestones for setting forth specific technology transfer activities under each program area;

"(D) include annual and five-year cost estimates for individual programs under this Act; and

"(E) identify program areas for which funding levels have been changed from the previous year's Plan.

"(6) Within one year after the date of the enactment of the Energy Policy Act of 1992, the Secretary shall submit a revised management plan under this section to Congress. Thereafter, the Secretary shall submit a management plan every three years at the time of submittal of the President's annual budget submission to the Congress.".

(d) CONFORMING AMENDMENTS.—The Renewable Energy and Energy Efficiency Technology Competitiveness Act of 1989 (42 U.S.C. 12001 et seq.) is further amended—

(1) in section 2(b)—

(A) by striking "authority contained in" and all that follows through "applicable to the Secretary" and inserting in lieu thereof "section 3001 of the Energy Policy Act of 1992"; and

(B) by striking "and demonstration" and inserting in lieu thereof "demonstration, and commercial application";

(2) in section 2(b)(4)—

(A) by striking "research and development"; and

(B) by striking "joint ventures" and inserting in lieu thereof "demonstration and commercial application projects";

(3) in section 2(c), by striking "the authority contained in" and all that follows and inserting in lieu thereof "section 3001 of the Energy Policy Act of 1992, is authorized and directed to—

"(1) pursue a program of research, development, demonstration, and commercial application with the private sector, to achieve the purpose of this Act, including the goals established under section 4; and

"(2) undertake demonstration and commercial application projects as provided in section 6.";

(4) in section 3—

(A) by striking paragraph (2);

(B) by redesignating paragraphs (3), (4), and (5) as paragraphs (2), (3), and (4), respectively;

(C) in paragraph (4), as so redesignated by subparagraph (B) of this paragraph—

(i) by striking "joint venture" and inserting in lieu thereof "demonstration and commercial application project";

(ii) by striking "venture" and inserting in lieu thereof "demonstration and commercial application project"; and

(iii) by striking "and " at the end thereof; and

(D) by inserting after paragraph (4), as so redesignated by subparagraph (B) of this paragraph, the following new paragraph:

"(5) the term 'source reduction' means any practice which—

"(A) reduces the amount of any hazardous substance, pollutant, or contaminant entering any waste stream or otherwise released into the environment, including fugitive emissions, prior to recycling, treatment, or disposal; and

"(B) reduces the hazards to the public health and the environment associated with the release of such substances, pollutants, or contaminants,

including equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, and inventory control, but not including any practice which alters the physical, chemical, or biological characteristics or the volume of a hazardous substance, pollutant, or contaminant through a process or activity which itself is not integral to and necessary for the production of a product or the providing of a service;"; and

(5) in section 9(a), by striking ", projects, and joint ventures" and inserting in lieu thereof "and projects".

SEC. 1203. RENEWABLE ENERGY EXPORT TECHNOLOGY TRAINING.

(a) ESTABLISHMENT OF PROGRAM.—The Secretary, through the Agency for International Development, shall establish a program for the training of individuals from developing countries in the operation and maintenance of renewable energy and energy efficiency technologies in accordance with this section. The Secretary and the Administrator of the Agency for International Development shall, within one year after the date of enactment of this Act, enter into a written agreement to carry out this program.

(b) PURPOSE.—The purpose of the program established under this section shall be to train appropriate persons in the system design, operation, and maintenance of renewable energy and energy efficiency equipment manufactured in the United States, including equipment for water pumping, heating and purification, and the production of electric power in remote areas.

(c) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary $6,000,000 for each of the fiscal years 1994, 1995, and 1996, to carry out this section.

SEC. 1204. RENEWABLE ENERGY ADVANCEMENT AWARDS.

(a) AUTHORITY.—The Secretary shall make Renewable Energy Advancement Awards in recognition of developments that advance the practical application of biomass, geothermal, hydroelectric, pho-

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tovoltaic, solar thermal, ocean thermal, and wind technologies to consumer, utility, or industrial uses, in accordance with this section. Except as provided in subsection (f), Renewable Energy Advancement Awards shall include a cash award.

(b) SELECTION CRITERIA.—The Secretary, in consultation with the Advisory Committee on Demonstration and Commercial Application of Renewable Energy and Energy Efficiency Technologies (in this section referred to as the "Advisory Committee"), under section 6 of the Renewable Energy and Energy Efficiency Technology Competitiveness Act of 1989, shall develop criteria to be applied in the selection of award recipients under this section. Such criteria shall include the following:

(1) The degree to which the technological development increases the utilization of renewable energy.

(2) The degree to which the development will have a significant impact, by benefitting a large number of people, by reducing the costs of an important industrial process or commercial product or service, or otherwise.

(3) The ingenuity of the development.

(4) Whether the application has significant export potential.

(5) The environmental soundness of the development.

(c) SELECTION.—Beginning in fiscal year 1994, and annually thereafter for a period of 10 years, the Secretary, in consultation with the Advisory Committee, shall select developments described in subsection (a) that are worthy of receiving an award under this section, and shall make such awards.

(d) ELIGIBILITY.—Awards may be made under this section only to individuals who are United States nationals or permanent resident aliens, or to non-Federal organizations that are organized under the laws of the United States or the laws of a State of the United States.

(e) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary $50,000 for each of the fiscal years 1994, 1995, and 1996 for carrying out this section.

(f) AWARDS MADE IN ABSENCE OF APPROPRIATIONS.—The Secretary shall make honorary awards under this section if sufficient funds are not available for financial awards in any fiscal year.

SEC. 1205. STUDY OF TAX AND RATE TREATMENT OF RENEWABLE ENERGY PROJECTS.

(a) The Secretary, in conjunction with State regulatory commissions, shall undertake a study to determine if conventional taxation and ratemaking procedures result in economic barriers to or incentives for renewable energy power plants compared to conventional power plants.

(b) Within 1 year after the date of the enactment of this Act, the Secretary shall submit a report to the Congress on the results of the study undertaken under subsection (a).

SEC. 1206. STUDY OF RICE MILLING ENERGY BY-PRODUCT MARKETING.

The Department of Energy shall conduct a study to facilitate the marketing of energy byproducts from rice milling.

SEC. 1207. DUTIES OF INTERAGENCY WORKING GROUP ON RENEWABLE ENERGY AND ENERGY EFFICIENCY EXPORTS.

(a) INTERAGENCY WORKING GROUP.—Section 256(d) of the Energy Policy and Conservation Act (42 U.S.C. 6276(d)) is amended to read as follows:

"(d) INTERAGENCY WORKING GROUP.—

"(1) ESTABLISHMENT.—(A) There shall be established an interagency working group that, in consultation with the representative industry groups and relevant agency heads, shall make recommendations to coordinate the actions and programs of the Federal Government affecting exports of renewable energy and energy efficiency products and services. The interagency working group shall establish a program to inform foreign countries of the benefits of policies that would increase energy efficiency or would allow facilities that use renewable energy to compete effectively with producers of energy from nonrenewable sources.

"(B) There shall be established an Interagency Working Subgroup on Renewable Energy and an Interagency Working Subgroup on Energy Efficiency that shall, in consultation with representative industry groups, nonprofit organizations, and relevant Federal agencies, make recommendations to coordinate the actions and programs of the Federal Government to promote the export of domestic renewable energy and energy efficiency products and services, respectively.

"(C) The Secretary of Energy, or the Secretary's designee, shall chair the interagency working group and each subgroup established under this paragraph. The Administrator of the Agency for International Development and the Secretary of Commerce, or their designees, shall be members of both subgroups established under this paragraph. The Secretary shall provide staff for carrying out the functions of the interagency working group and each subgroup established under this paragraph. The heads of appropriate agencies may detail such personnel and may furnish such services to such group and subgroups, with or without reimbursement, as may be necessary to carry out their functions.

"(2) DUTIES OF THE INTERAGENCY WORKING SUBGROUPS.—(A) The interagency working subgroups established under paragraph (1)(B), through the member agencies of the interagency working group, shall promote the development and application in foreign countries of renewable energy and energy efficiency products and services, respectively, that—

"(i) reduce dependence on unreliable sources of energy by encouraging the use of sustainable biomass, wind, small-scale hydroelectric, solar, geothermal, and other renewable energy and energy efficiency products and services; and

"(ii) use hybrid fossil-renewable energy systems.

"(B) In addition, the interagency working subgroups shall explore mechanisms for assisting domestic firms, particularly small businesses, with the export of their renewable energy and energy efficiency products and services and with the identification of potential projects.

"(3) TRAINING AND ASSISTANCE.—The interagency working subgroups shall encourage the member agencies of the interagency working group to—

"(A) provide technical training and education for international development personnel and local users in their own country;

"(B) provide financial and technical assistance to nonprofit institutions that support the marketing and export efforts of domestic companies that provide renewable energy and energy efficiency products and services;

"(C) develop environmentally sustainable renewable energy and energy efficiency projects in foreign countries;

"(D) provide technical assistance and training materials to loan officers of the World Bank, international lending institutions, commercial and energy attaches at embassies of the United States and other appropriate personnel in order to provide information about renewable energy and energy efficiency products and services to foreign governments or other potential project sponsors;

"(E) support, through financial incentives, private sector efforts to commercialize and export renewable energy and energy efficiency products and services; and

"(F) augment budgets for trade and development programs in order to support pre-feasibility or feasibility studies for projects that utilize renewable energy and energy efficiency products and services.".

(b) FUNCTIONS.—Section 256(f) of the Energy Policy and Conservation Act (42 U.S.C. 6276(f)) is amended by inserting "and energy efficiency" after "renewable energy" each place it appears.

(c) DEFINITIONS.—Section 256(g) of the Energy Policy and Conservation Act (42 U.S.C. 6276(g)) is repealed.

(d) AUTHORIZATION OF APPROPRIATIONS.—Section 256(h) of the Energy Policy and Conservation Act (42 U.S.C. 6276(h)) is amended to read as follows:

"(h) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary for purposes of carrying out the programs under subsections (d) and (e) $10,000,000, to be divided equitably between the interagency working subgroups based on program requirements, for each of the fiscal years 1993 and 1994, and such sums as may be necessary for fiscal year 1995 to carry out the purposes of this subtitle.".

SEC. 1208. STUDY OF EXPORT PROMOTION PRACTICES.

Section 256(d) of the Energy Policy and Conservation Act (42 U.S.C. 6276(d)) as amended by section 1208 of this Act, is further amended by adding at the end the following new paragraph:

"(4) The interagency working group shall conduct a study of subsidies, incentives, and policies that foreign countries use to promote exports of their own renewable energy and energy efficiency technologies and products. Such study shall also identify foreign trade barriers to the import of renewable energy and energy efficiency technologies and products produced in the United States. The interagency working group shall report to the appropriate committees of the House of Representatives and the Senate the results of

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such study within 18 months after the date of the enactment of the Energy Policy Act of 1992.".

SEC. 1209. DATA SYSTEM AND ENERGY TECHNOLOGY EVALUATION.

The Secretary of Commerce, in his or her role as a member of the interagency working group established under section 256 of the Energy Policy and Conservation Act (42 U.S.C. 6276), shall—

(1) develop a comprehensive data base and information dissemination system, using the National Trade Data Bank and the Commercial Information Management System of the Department of Commerce, that will provide information on the specific energy technology needs of foreign countries, and the technical and economic competitiveness of various renewable energy and energy efficiency products and technologies;

(2) make such information available to industry, Federal and multilateral lending agencies, nongovernmental organizations, host-country and donor-agency officials, and such others as the Secretary of Commerce considers necessary; and

(3) prepare and transmit to the Congress not later than June 1, 1993, and biennially thereafter, a comprehensive report evaluating the full range of energy and environmental technologies necessary to meet the energy needs of foreign countries, including—

(A) information on the specific energy needs of foreign countries;

(B) an inventory of United States technologies and services to meet those needs;

(C) an update on the status of ongoing bilateral and multilateral programs which promote United States exports of renewable energy and energy efficiency products and technologies; and

(D) an evaluation of current programs (and recommendations for future programs) that develop and promote energy efficiency and sustainable use of indigenous renewable energy resources in foreign countries to reduce the generation of greenhouse gases.

SEC. 1210. OUTREACH.

(a) OUTREACH.—The interagency working group established under section 256(d)(1)(A) of the Energy Policy and Conservation Act and the Secretary of Commerce shall select one individual who is experienced in renewable energy and energy efficiency products and technologies to be assigned by the Secretary of Commerce to an office of the United States and Foreign Commercial Service in the Pacific Rim, and one such individual to be assigned by the Secretary of Commerce to an office of the United States and Foreign Commercial Service in the Caribbean Basin, for the sole purpose of providing information concerning domestic renewable energy and energy efficiency products, technologies, and industries to territories, foreign governments, industries, and other appropriate persons.

(b) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary for the purposes of this section $500,000 for each of the fiscal years 1993 and 1994, and such sums as may be necessary for fiscal year 1995.

SEC. 1211. INNOVATIVE RENEWABLE ENERGY TECHNOLOGY TRANSFER PROGRAM.

(a) ESTABLISHMENT OF PROGRAM.—The Secretary, through the Agency for International Development, and in consultation with the other members of the interagency working group established under section 256(d) of Energy Policy and Conservation Act (in this section referred to as the "interagency working group"), shall establish a renewable energy technology transfer program to carry out the purposes described in subsection (b). Within 150 days after the date of the enactment of this Act, the Secretary and the Administrator of the Agency for International Development shall enter into a written agreement to carry out this section. The agreement shall establish a procedure for resolving any disputes between the Secretary and the Administrator regarding the implementation of specific projects. With respect to countries not assisted by the Agency for International Development, the Secretary may enter into agreements with other appropriate Federal agencies. If the Secretary and the Administrator, or the Secretary and an agency described in the previous sentence, are unable to reach an agreement, each shall send a memorandum to the President outlining an appropriate agreement. Within 90 days after receipt of either memorandum, the President shall determine which version of the agreement shall be in effect. Any agreement entered into under this subsection shall be provided to the appropriate committees of the Congress and made available to the public.

(b) PURPOSES OF THE PROGRAM.—The purposes of the technology transfer program under this section are to—

(1) reduce the United States balance of trade deficit through the export of United States renewable energy technologies and technological expertise;

(2) retain and create manufacturing and related service jobs in the United States;

(3) encourage the export of United States renewable energy technologies, including services related thereto, to those countries that have a need for developmentally sound facilities to provide energy derived from renewable resources;

(4) develop markets for United States renewable energy technologies to be utilized in meeting the energy and environmental requirements of foreign countries;

(5) better ensure that United States participation in energy-related projects in foreign countries includes participation by United States firms as well as utilization of United States technologies that have been developed or demonstrated in the United States through publicly or privately funded demonstration programs;

(6) ensure the introduction of United States firms and expertise in foreign countries;

(7) provide financial assistance by the Federal Government to foster greater participation by United States firms in the financing, ownership, design, construction, or operation of renewable energy technology projects in foreign countries;

(8) assist foreign countries in meeting their energy needs through the use of renewable energy in an environmentally ac-

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ceptible manner, consistent with sustainable development policies; and

(9) assist United States firms, especially firms that are in competition with firms in foreign countries, to obtain opportunities to transfer technologies to, or undertake projects in, foreign countries.

(c) IDENTIFICATION.—Pursuant to the agreements required by subsection (a), the Secretary, through the Agency for International Development, and after consultation with the interagency working group, United States firms, and representatives from foreign countries, shall develop mechanisms to identify potential energy projects in host countries, and shall identify a list of such projects within 240 days after the date of the enactment of this Act, and periodically thereafter.

(d) FINANCIAL MECHANISMS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, shall—

(A) establish appropriate financial mechanisms to increase the participation of United States firms in energy projects utilizing United States renewable energy technologies, and services related thereto, in developing countries;

(B) utilize available financial assistance authorized by this section to counterbalance assistance provided by foreign governments to non-United States firms; and

(C) provide financial assistance to support projects.

(2) The financial assistance authorized by this section may be—

(A) provided in combination with other forms of financial assistance, including non-United States funding that is available to the project; and

(B) utilized to assist United States firms in the development of innovative financing packages for renewable energy technology projects that utilize other financial assistance programs available through the Federal Government.

(3) United States obligations under the Arrangement on Guidelines for Officially Supported Export Credits established through the Organization for Economic Cooperation and Development shall be applicable to this section.

(e) SOLICITATIONS FOR PROJECT PROPOSALS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, within one year after the date of the enactment of this Act, and subsequently as appropriate thereafter, shall solicit proposals from United States firms for the design, construction, testing, and operation of the project or projects identified under subsection (c) which propose to utilize a United States renewable energy technology. Each solicitation under this section shall establish a closing date for receipt of proposals.

(2) The solicitation under this subsection shall, to the extent appropriate, be modeled after the RFP No. DE-PS01-90FE62271 Clean Coal Technology IV, as administered by the Department of Energy.

(3) Any solicitation made under this subsection shall include the following requirements:

(A) The United States firm that submits a proposal in response to the solicitation shall have an equity interest in the proposed project.

(B) The project shall utilize a United States renewable energy technology, including services related thereto, in meeting the applicable energy and environmental requirements of the host country.

(C) Proposals for projects shall be submitted by and undertaken with a United States firm, although a joint venture or other teaming arrangement with a non-United States manufacturer or other non-United States entity is permissible.

(f) ASSISTANCE TO UNITED STATES FIRMS.—Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, and in consultation with the interagency working group, shall establish a procedure to provide financial assistance to United States firms under this section for a project identified under subsection (c) where solicitations for the project are being conducted by the host country or by a multilateral lending institution.

(g) OTHER PROGRAM REQUIREMENTS.—Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, and in consultation with the working group, shall—

(1) establish eligibility criteria for host countries;

(2) periodically review the energy needs of such countries and export opportunities for United States firms for the development of projects in such countries;

(3) consult with government officials in host countries and, as appropriate, with representatives of utilities or other entities in host countries, to determine interest in and support for potential projects; and

(4) determine whether each project selected under this section is developmentally sound, as determined under the criteria developed by the Development Assistance Committee of the Organization for Economic Cooperation and Development.

(h) SELECTION OF PROJECTS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, shall, not later than 120 days after receipt of proposals in response to a solicitation under subsection (e), select one or more proposals under this section.

(2) In selecting a proposal under this section, the Secretary, through the Agency for International Development, shall consider—

(A) the ability of the United States firm, in cooperation with the host country, to undertake and complete the project;

(B) the degree to which the equipment to be included in the project is designed and manufactured in the United States;

(C) the long-term technical and competitive viability of the United States technology, and services related thereto, and the ability of the United States firm to compete in the development of additional energy projects using such technology in the host country and in other foreign countries;

(D) the extent of technical and financial involvement of the host country in the project;

(E) the extent to which the proposed project meets the purposes stated in section 1201(b);

(F) the extent of technical, financial, management, and marketing capabilities of the participants in the project, and

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the commitment of the participants to completion of a successful project in a manner that will facilitate acceptance of the United States technology for future application; and

(G) such other criteria as may be appropriate.

(3) In selecting among proposed projects, the Secretary shall seek to ensure that, relative to otherwise comparable projects in the host country, a selected project will meet 1 or more of the following criteria:

(A) It will reduce environmental emissions to an extent greater than required by applicable provisions of law.

(B) It will make greater use of indigenous renewable energy resources.

(C) It will be a more cost-effective technological alternative, based on life cycle capital and operating costs per unit of energy produced and, where applicable, costs per unit of product produced.

Priority in selection shall be given to those projects which, in the judgment of the Secretary, best meet one or more of these criteria.

(i) UNITED STATES-ASIA ENVIRONMENTAL PARTNERSHIP.—Activities carried out under this section shall be coordinated with the United States-Asia Environmental Partnership.

(j) BUY AMERICA.—In carrying out this section, the Secretary, through the Agency for International Development, and pursuant to the agreements under subsection (a), shall ensure—

(1) the maximum percentage, but in no case less than 50 percent, of the cost of any equipment furnished in connection with a project authorized under this section shall be attributable to the manufactured United States components of such equipment; and

(2) the maximum participation of United States firms.

In determining whether the cost of United States components equals or exceeds 50 percent, the cost of assembly of such United States components in the host country shall not be considered a part of the cost of such United States component.

(k) REPORTS TO CONGRESS.—The Secretary and the Administrator of the Agency for International Development shall report annually to the Committee on Energy and Natural Resources of the Senate and the appropriate committees of the House of Representatives on the progress being made to introduce renewable energy technologies into foreign countries.

(l) DEFINITIONS.—For purposes of this section—

(1) the term "host country" means a foreign country which is—

(A) the participant in or the site of the proposed renewable energy technology project; and

(B) either—

(i) classified as a country eligible to participate in development assistance programs of the Agency for International Development pursuant to applicable law or regulation; or

(ii) a developing country.

(2) the term "developing country" includes, but is not limited to, countries in Central and Eastern Europe or in the independent states of the former Soviet Union.

(m) AUTHORIZATION FOR PROGRAM.—There are authorized to be appropriated to the Secretary to carry out the program required by this section, $100,000,000 for each of the fiscal years 1993, 1994, 1995, 1996, 1997, and 1998.

SEC. 1212. RENEWABLE ENERGY PRODUCTION INCENTIVE.

(a) INCENTIVE PAYMENTS.—For electric energy generated and sold by a qualified renewable energy facility during the incentive period, the Secretary shall make, subject to the availability of appropriations, incentive payments to the owner or operator of such facility. The amount of such payment made to any such owner or operator shall be as determined under subsection (e). Payments under this section may only be made upon receipt by the Secretary of an incentive payment application which establishes that the applicant is eligible to receive such payment and which satisfies such other requirements as the Secretary deems necessary. Such application shall be in such form, and shall be submitted at such time, as the Secretary shall establish.

(b) QUALIFIED RENEWABLE ENERGY FACILITY.—For purposes of this section, a qualified renewable energy facility is a facility which is owned by a State or any political subdivision of a State (or an agency, authority, or instrumentality of a State or a political subdivision), by any corporation or association which is wholly owned, directly or indirectly, by one or more of the foregoing, or by a nonprofit electrical cooperative and which generates electric energy for sale in, or affecting, interstate commerce using solar, wind, biomass, or geothermal energy, except that—

(1) the burning of municipal solid waste shall not be treated as using biomass energy; and

(2) geothermal energy shall not include energy produced from a dry steam geothermal reservoir which has—

(A) no mobile liquid in its natural state;

(B) steam quality of 95 percent water; and

(C) an enthalpy for the total produced fluid greater than or equal to 1200 Btu/lb (British thermal units per pound).

(c) ELIGIBILITY WINDOW.—Payments may be made under this section only for electricity generated from a qualified renewable energy facility first used during the 10-fiscal year period beginning with the first full fiscal year occurring after the enactment of this section.

(d) PAYMENT PERIOD.—A qualified renewable energy facility may receive payments under this section for a 10-fiscal year period. Such period shall begin with the fiscal year in which electricity generated from the facility is first eligible for such payments.

(e) AMOUNT OF PAYMENT.—

(1) IN GENERAL.—Incentive payments made by the Secretary under this section to the owner or operator of any qualified renewable energy facility shall be based on the number of kilowatt hours of electricity generated by the facility through the use of solar, wind, biomass, or geothermal energy during the

payment period referred to in subsection (d). For any facility, the amount of such payment shall be 1.5 cents per kilowatt hour, adjusted as provided in paragraph (2).

(2) ADJUSTMENTS.—The amount of the payment made to any person under this subsection as provided in paragraph (1) shall be adjusted for inflation for each fiscal year beginning after calendar year 1993 in the same manner as provided in the provisions of section 29(d)(2)(B) of the Internal Revenue Code of 1986, except that in applying such provisions the calendar year 1993 shall be substituted for calendar year 1979.

(f) SUNSET.—No payment may be made under this section to any facility after the expiration of the 20-fiscal year period beginning with the first full fiscal year occurring after the enactment of this section, and no payment may be made under this section to any facility after a payment has been made with respect to such facility for a 10-fiscal year period.

(g) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary for fiscal years 1993, 1994, and 1995 such sums as may be necessary to carry out the purposes of this section.

TITLE XIII—COAL

Subtitle A—Research, Development, Demonstration, and Commercial Application

SEC. 1301. COAL RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIAL APPLICATION PROGRAMS.

(a) ESTABLISHMENT.—The Secretary shall, in accordance with section 3001 and 3002 of this Act, conduct programs for research, development, demonstration, and commercial application on coal-based technologies. Such research, development, demonstration, and commercial application programs shall include the programs established under this subtitle, and shall have the goals and objectives of—

(1) ensuring a reliable electricity supply;

(2) complying with applicable environmental requirements;

(3) achieving the control of sulfur oxides, oxides of nitrogen, air toxics, solid and liquid wastes, greenhouse gases, or other emissions resulting from coal use or conversion at levels of proficiency greater than or equal to applicable currently available commercial technology;

(4) achieving the cost competitive conversion of coal into energy forms usable in the transportation sector;

(5) demonstrating the conversion of coal to synthetic gaseous, liquid, and solid fuels;

(6) demonstrating, in cooperation with other Federal and State agencies, the use of coal-derived fuels in mobile equipment, with opportunities for industrial cost sharing participation;

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TAB 7

Energy Policy Act of 1992
Joint Explanatory Statement
of the Committee of Conference

JOINT EXPLANATORY STATEMENT OF THE COMMITTEE OF CONFERENCE

The managers on the part of the House and the Senate at the conference on the disagreeing votes of the two Houses on the amendments of the Senate to the bill (H.R. 776) to provide for improved energy efficiency submit the following joint statement to the House and the Senate in explanation of the action agreed upon by the managers and recommended in the accompanying confer.ˑ̉e report.

TITLE I—ENERGY EFFICIENCY

SUBTITLE A—BUILDINGS

Sec. 101. Building Energy Efficiency Standards

Section 101(c) would amend the Cranston-Gonzalez National Affordable Housing Act (P.L. 101-625) to ensure that the Secretary of Housing and Urban Development develops energy efficiency standards for new homes financed through Federal mortgage programs as required by that Act. The subsection also expands the coverage of the standards from HUD insured mortgages only, to the mortgage insurance and guarantee programs of the Departments of Agriculture and Veterans Affairs. Such standards shall meet or exceed the requirements of the Council of American Building Officials Model Energy Code 1992 (CABO-MEC 1992) or, in the case of multifamily high rises, the requirements of the American Society of Heating, Refrigerating, and Air-Conditioning Engineers standards (ASHRAE 90.1-1989), and shall be cost-effective with respect to construction and operating costs on a life-cycle cost basis. The Conferees believe that these consensus standards are cost-effective with respect to construction and operating costs on a life-cycle cost basis. If, in carrying out their responsibilities under this subsection, the Secretaries wish to conduct life-cycle cost analyses, they should use a 25 or 30 year term to reflect the facts that houses have long useful lives and are commonly financed through 30 year mortgages.

SUBTITLE B—UTILITIES

Sec. 111. Encouragement of Investments in Conservation and Energy Efficiency by Electric Utilities

This section would amend the Public Utility Regulatory Policies Act of 1978 to require utilities and public utility commissions to consider requiring three new Federal standards:

1. integrated resource planning which compares supply and demand-side options on a systematic and comparable basis;

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2. cost recovery for energy efficiency programs and measures that makes them at least as profitable as supply side measures; and

3. rate changes that encourage investments in efficiency measures in generation, transmission and distribution of power.

Whether or not utilities and public utility commissions choose to implement these policies, they must hold a public hearing and state why they will not implement them. The Conferees recognize that a number of States have already implemented some or all of the standards encouraged under this section. The Conferees do not intend that such States go through additional rulemaking proceedings simply to satisfy the procedural requirement above, nor do they intend that States repeat such proceedings in the future. These States are encouraged to demonstrate that they have implemented the standards by referencing actions they have already taken. States have substantial discretion in how they implement the standards encouraged under this section.

It is the intent of this subtitle to promote energy efficiency, in particular by encouraging utilities, which have a unique relationship with their customers, to expand demand-side management (DSM) programs. It is also intended that utility commissions must consider the impact which these expanded DSM programs may have on small businesses already engaged in similar activities, and shall implement these standards so as to assure that utility actions will not provide utilities with unfair competitive advantages over such small businesses. It is further intended that whenever practicable and consistent with energy efficiency goals, utility commissions will encourage approaches to the implementation of DSM activities that would be mutually beneficial to utilities and small businesses, such as through joint utility-small business arrangements using rebates or vouchers.

The subsection dealing with small business protection neither precludes, nor mandates, the adoption of competitive bidding for demand-side management services. By adding this provision, the Conferees do not intend that utilities be precluded from engaging in energy conservation, energy efficiency or other demand-side measures.

Whether utilities engage in such activities should continue to be determined by state laws and state regulatory commissions, keeping in mind the requirements of this subsection. The Conferees intend that nothing in this subsection in any way interfere with the ability of utilities to assure safe and reliable service. State regulatory commissions are encouraged to utilize their existing authority in implementing this subsection; the implementation of this subsection is not intended to require the creation of new administrative or regulatory procedures.

Sec. 114. Amendment of Hoover Power Plant Act

Section 114 would amend the Hoover Power Plant Act of 1984 to require the Western Area Power Administration (WAPA) to issue rules requiring all but its smallest customers to engage in integrated resource planning (IRP). The Conferees recognize the efforts that many customers have already undertaken with respect to IRP. The Conferees further recognize that these customers vary in size and capability to plan, and therefore intend that regulations be flexible enough to allow for reasonable variations in compliance requirements.

In section 204(b) of such Act, as amended by this section, the customer is required, in preparation and development of the IRP, to provide for full public participation, including participation of governing boards. This language reflects the sound policy that better decisions result when the affected customers are involved in the resource planning process. Preference entities serve the public and are accountable to their consumers. By allowing the consumer to participate in the IRP preparation and development process, recognition of the public interest is assured.

Section 204(c), as amended, would direct the Administrator to accept integrated resource plans that are currently being implemented by customers under other programs as fulfilling the requirements of this provision "to the extent such plan substantially complies with requirements of this title." The Conferees intend for the Administrator to be flexible in determining what satisfies the "substantial compliance" standard. IRP plans to take significant resources to plan and implement.

Finally, it is not the Conferees' intent that WAPA force changes in customers' approved IRP plans. WAPA should accept good faith efforts to comply with approved plans as generally satisfying compliance standards.

Sec. 115. Encouragement of Investments in Conservation and Energy Efficiency by Gas Utilities

This section would amend the natural gas provisions of the Public Utility Regulatory Policies Act of 1978 to require utilities and State regulatory commissions to consider requiring two new Federal standards:

1. implement integrated resource planning for State regulated gas utilities; and
2. allow State regulated gas utilities to earn a profit on investments in energy efficiency.

States may choose not to implement these requirements, but they must hold a hearing and state why they are not implementing them.

The Conferees recognize that a number of States have already implemented some or both of the standards encouraged under this section. The Conferees do not intend that such States go through additional rulemaking proceedings simply to satisfy the procedural requirements above. These States are encouraged to demonstrate that they have implemented the standards by referencing actions they have already taken. The Conferees believe that States should have substantial discretion in how they implement the standards encouraged under this section.

It is intended that Integrated Resource Planning (IRP) be considered only for local gas distribution companies who directly serve ultimate users of gas. In examining natural gas supply options under IRP, it is not intended that the sources, conditions, or other characteristics of the upstream supply of gas be analyzed. Rather, the IRP is intended to examine and compare demand-side options with the general option of additional supplies to end use customers by the local gas distribution company.

The subsection in this section regarding the competitive impact of the implementation of these standards on small businesses has the same intent as that described under section 111.

SUBTITLE C—STANDARDS

In general

The provisions of this subtitle would significantly expand the coverage of the appliance energy efficiency standards program and the energy labeling program under the Energy Policy and Conservation Act (EPCA). It is the intent of the Conferees that the Secretary shall seek to harmonize these standards internationally, particularly with standards established or under development in Canada and Mexico, nations with which the United States conducts substantial trade. Such harmonization will simplify enforcement, reduce impediments to trade, and will reduce burdens on manufacturers.

In addition, the Conferees have concerns regarding the adequacy of the current enforcement penalties under EPCA. These penalties were established many years ago. Accordingly, the conferees expect the Secretary to review the adequacy of the enforcement provisions of these programs and to recommend changes to the Congress, if appropriate.

Sec. 121. Energy Efficiency Labeling for Windows and Window Systems

The National Fenestration Rating Council (NFRC) is initially directed to develop this voluntary rating program according to commonly accepted procedures for the development of national testing procedure and labeling programs. Such commonly accepted procedures are those recognized by the Federal Trade Commission (FTC), or that are consistent with FTC policy.

In addition, it is intended that, should NFRC develop this program, its implementation and administration also will be in accordance with commonly accepted procedures. Such procedures must assure, at a minimum, that NFRC has sufficient oversight and authority to assure that accreditation and certification procedures result in compliance with its program.

Sec. 125. Energy Efficiency Labeling for Commercial Office Equipment

This section would require the Secretary to provide financial assistance to support the development of a voluntary national testing and information program for commercial office equipment in accordance with commonly accepted procedure for the development of such testing and information programs. Such commonly accepted procedures are those recognized by the Federal Trade Commission or consistent with FTC policy.

If such a voluntary program is not established within 3 years, then the Secretary and the Federal Trade Commission are directed to develop test procedures and labeling rules for commercial office equipment.

Sec. 126. Energy Efficiency Labeling for Luminaries

This section would require the Secretary to provide financial assistance to support the development of a voluntary national testing and information program for luminaries in accordance with commonly accepted procedures for the development of such testing and information programs. Such commonly accepted procedures are those recognized by the Federal Trade Commission or that are consistent with FTC policy.

Sec. 127. Report on the Potential of Cooperative Advanced Appliance Development

This section would require the Secretary, in consultation with the Administrator of EPA, to prepare and submit a report to Congress on the potential for the development and commercialization of appliances which are substantially more efficient that those required by Federal or State law. Any recommendations relate to the commercialization of such advanced appliances should take into account any issues regarding the marketing of such appliances.

The Conferees are aware that the Environmental Protection Agency is already engaged in supporting industry efforts to develop high efficiency refrigerators and other products and do not intend this study to delay those ongoing efforts. The study should particularly focus on those appliances and products that EPA is not currently working on. In addition, it is intended that the two agencies will coordinate their efforts in this area and avoid duplication of effort.

SUBTITLE F—FEDERAL AGENCY ENERGY MANAGEMENT

Sec. 155. Energy Savings Performance Contracts

This section would amend title VIII of the National Energy Conservation Policy Act to further promote the use of energy performance contracts.

It is estimated that the Federal government could reduce its energy costs by approximately $1 billion annually through the installation of energy efficiency measures in its buildings. However, the budget deficit has prevented the necessary investments from being made by the government.

Energy savings performance contracts are a mechanism through which private sector funds can finance Federal energy efficiency improvements. The Conferees recognize that these contracts differ significantly from traditional Federal procurement contracts. Under these contracts, the contractor is expected to bear the risk of performance, make a significant initial capital investment, guarantee significant energy savings to the government agency, and from these savings the agency, in effect, makes payment to the contractor.

Because these contracts differ significantly from traditional Federal contracts, existing contracting regulations may be inconsistent. Current regulations were not formulated for application to energy performance contracts. Accordingly, this provision authorizes and directs the Secretary, with the concurrence of the Federal Acquisition Regulation (FAR) Council, to develop procedures and methods for the implementation of such contracts. To maximize the benefits to the government of such contracts, the Secretary, with the concurrence of the FAR Council, is given wide latitude to develop substitute regulations where existing procurement regulations are inconsistent with the goal of promoting energy performance contracts. These substitute regulations must, however, be consistent with Federal procurement laws.

The section requires new procurement regulations be issued within 180 days, and the Conferees expect prompt action to carry out this requirement consistent with public participation.

It is also the expectation of the Conferees that uniform regulations will be developed both to relieve Federal agencies of the need to individually develop performance contract procedures and methods and to encourage energy service companies to contract with Federal agencies on a uniform basis.

Finally, subsection (a)(2)(D)(ii) authorizes multiyear contracts for up to 25 years, provided funds are available for payments to the contractor in the first year. The section creates special protections for the taxpayer in view of the risk inherent in committing the Federal government to such multi-year contracts. For example, the government may be liable for payment of a substantial cancellation fee. Accordingly, subsection (a)(2)(D)(iii) requires that a Federal agency must notify the appropriate authorizing and appropriating committees of the Congress before signing such a contract if it contains a clause permitting a cancellation charge in excess of $750,000. Subsection (a)(2)(D)(i) also provides that such contracts be awarded in a competitive manner, and the Conferees intend that Federal agencies endeavor to secure the broadcast participation by qualified firms.

TITLE II—NATURAL GAS

The Conferees agreed not to include most of the text of title II of H.R. 776, regarding natural gas pipelines, in the conference report. The one exception is that the conference report includes an amended section 201 regarding fewer restrictions on certain natural gas imports and exports.

The decision not to include most of title II includes section 214 of the House bill regarding State regulation of the production of natural gas, *i.e.*, prorationing. However, the Conferees included a new section 202, stating the sense of the Congress that natural gas consumers and producers, and the national economy, are best served by a competitive natural gas wellhead market. One of the reasons that Conferees decided not to include section 214 is the recognition that, under existing law, a state cannot use its proration authority for the purpose of restricting supplies and raising the price of natural gas. *E.g.*, *Northwest Central Pipeline Corp.* v. *State Corporation Commission of Kansas*, 489 U.S. 493 (1989); *Transcontinental Gas Pipe Line Corp.* v. *State Oil and Gas Board of Miss.*, 474 U.S. 409 (1986). The Conferees recognize that both the Congress and the U.S. Supreme Court have long recognized the necessity of state-administered systems for defining and enforcing property rights in natural gas reservoirs. Still, states may not regulate natural gas production without regard to the effect that such regulation may have on interstate commerce. Under existing law, a method of regulating production must: (1) achieve or advance the legitimate state interests in conserving natural resources, preventing waste, and protecting correlative rights; and (2) not be preempted by, or overly disruptive of, Federal law. Should a state use its proration authority for the purpose of restricting supplies and raising the price of natural gas, the Conferees do not believe that such regulation would satisfy the standard under existing law. The Conferees believe that the new section 202, stating the sense of the Congress, is consistent with existing law.

TITLE IV—ALTERNATIVE FUELS AND NON-FEDERAL PROGRAMS

Section 408 authorizes the Federal Energy Regulatory Commission (FERC), under the Natural Gas or Federal Power Acts, to consider the environmental and other benefits of research and development efforts on Alternative Fuel Vehicles (AFV) by the Gas Research Institute (GRI) or the Electric Power Research Institute.

If the benefits exceed the direct costs of the research and development, the FERC may allow natural gas pipelines and electric utilities to recover the costs in their "just and reasonable" rate filings under the Natural Gas and the Federal Power Acts.

Cost sharing is required to the maximum practicable extent. This section recognizes that cost sharing may not be practicable for all natural gas transportation, pollution control, and emissions reduction projects.

The cofunding provisions are intended to become effective for new projects initiated after the date of enactment of this legislation and would not require GRI to cancel existing contracts to comply with the cofunding provision.

TITLE V—AVAILABILITY AND USE OF REPLACEMENT FUELS, ALTERNATIVE FUELS, AND ALTERNATIVE FUELED PRIVATE VEHICLES

The intent of section 501(a)(1) is *not* to cover all affiliates or divisions of the many large energy companies which have some, but not all, of their corporate units engaged in alternative fuels operations.

For example, the oil and gas production affiliate or division of a major energy company described in 501(a)(1)(C) would be covered; so might a propane pipeline unit or a natural gas processing division, if the "substantially engaged" test is met.

But an oil tanker division, a gasoline marketing affiliate, or a petrochemical unit whose major operations are the production of plastics, for example, would not be covered.

The Secretary has broad discretion to define the coverage of this provision. For example, he may in his discretion exempt some crude oil-related operations of an oil and gas production affiliate (but not the gas-related operations), or the petrochemical operations of a covered methanol unit (but not the methanol-related business).

TITLE VII—ELECTRICITY

Under current law, the Securities and Exchange Commission has authority to permit, on a case-by-case basis, certain utility functions outside the United States. Further, new section 32 of PUHCA allows exempt wholesale generators located outside the United States to engage in both wholesale and retail generation. The provisions of new section 33 supplement these foreign options for utility operations and do not in any way limit any person's ability to pursue SEC approval under current law or the EWG course.

The definition of an EWG has been drafted to permit an EWG to sell wholesale power that it has not generated itself. Buyers of wholesale power may desire to purchase capacity in increments that exceed what the most economical unit would produce. Consequently, the legislation would permit an EWG, for example, to generate 350 Megawatts and purchase an additional 50 Megawatts in order to met a purchaser's 400 MW capacity need.

The definition of an exempt wholesale generator contained in section 32(a)(1) permits an exempt wholesale generator to own facilities and goods, such as fuel and related transportation, storage and handling facilities, reasonably necessary for the operation of its business.

Rates, charges, terms, and conditions for wholesale transmission services ordered under section 211 in all cases shall be just and reasonable, and not unduly discriminatory or preferential. The Conferees intend the term "associated services" to mean the cost of ancillary services such as back-up power, interconnection costs, and radial lines.

New section 212(h) of the Federal Power Act contains a savings clause for State laws dealing with retail wheeling. Thus, State laws that either prohibit or permit retail wheeling are unaffecting by this subsection. And, if otherwise valid, remain in full force and effect.

The Conferees do not intend to limit or modify the authority of State commissions to review the prudence or imprudence of wholesale purchases by retail utilities under their jurisdiction.

The Bonneville Power Administration (BPA) has set policies from time to time for furnishing transmission service on the Federal Columbia River Transmission System. BPA has done so under the laws which define its authority and obligations concerning transmission, which laws remain fully effective and applicable. It is expected that, when the FERC exercises its authority under section 211 to require BPA to provide transmission service, it will do so consistent with the laws governing BPA. Transmission contracts entered into in accordance with BPA's policies which are in existence on the date of enactment of this Act are unaffected by the FERC's new authority to order access to transmission controlled by BPA. Similarly, BPA's short-term transmission service allocation methodology for economy energy trades is also unaffected by the FERC's new authority to order access to transmission controlled by BPA. However, the FERC is not bound by the transmission policy choices BPA has made or may make in the future as to new firm transmission service requests.

A primary BPA obligation under the laws that define BPA's authority and obligations is to provide transmission service over available capacity for its customers within the Pacific Northwest as that region is defined in 16 U.S.C. section 839a(14). Historically, Bonneville Power Administration has built most of the intraregional bulk transmission facilities in the Pacific Northwest. This was done on the basis of a regional consensus and the understanding that BPA would make these transmission facilities available for transmission of power for BPA's power and transmission customers located in the Pacific Northwest. The utilities of the Pacific Northwest have relied and continue to rely on that transmission. BPA's use of its transmission system for firm transmission service contracts for generating resources serving BPA customer loads within the Pacific Northwest is not affected by any new authority under this Act to provide access for interregional arrangements.

The FERC shall not issue any order for transmission services under section 211 which is likely to cause the uncompensated spill of water from Federal or non-Federal reservoirs which otherwise could be used to generate electric energy, because of its displacement from a transmission system by energy transmitted under such an order. Such spill shall be deemed contrary to the public interest unless full compensation is provided to those entities suffering such spill. Nothing in the preceding sentences should be understood to limit such ability as the FERC may otherwise have under this Act to prevent or compensate other adverse impacts that may result from an order issued under section 211 or this section.

Rates for transmission services provided by BPA under an order issued under section 211 are to be established by BPA and reviewed by the FERC through the same process and using the same statutory requirements as are applicable to all other transmission rates established by BPA, with the additional requirement that such rates for transmission services must also be just and reasonable and not unduly discriminatory or preferential as determined by the FERC, taking into account BPA's other statutory authorities and responsibilities. Nothing in the Federal Power Act or BPA's organic legislation should be construed to prohibit the FERC from approving rates, terms and conditions for transmission services pursuant to section 211 which provide for the recovery of any increased costs or lost revenues due to foregone sales or purchases or other operating impacts resulting from such services, provided that similar approvals are in general accorded to utilities subject to sections 205 and 206.

BPA may establish rates of general applicability for FERC-ordered transmission service which, once approved by the FERC, will not be subject to review in individual cases but will be periodically reviewed and, as appropriate, revised along with BPA's general wholesale power and transmission rates. BPA may also establish, and the FERC may approve, terms and conditions of general applicability and sufficient specificity for FERC-ordered transmission services.

BPA's rates, terms and conditions for transmission services ordered by the FERC may differ from those required by the FERC of other entities subject to this Act. However, the effect of any transmission services ordered by the FERC under section 211 cannot be materially more or less favorable for BPA than for other entities subject to the FERC's transmission service orders pursuant to this Act with respect to: (1) overall cost recovery by the transmitting utility, and (2) economic impact on the transmitting utility.

The FERC has the responsibility to implement this Act, including section 212(i), and to consider and apply BPA's other federal statutes.

TITLE VIII—HIGH-LEVEL RADIOACTIVE WASTE

Section 801 addresses the Environmental Protection Agency's (EPA) generally applicable standards for protection of members of the public from release of radioactive materials into the accessible environment as a result of the disposal of spent nuclear fuel or high-level or transuranic radioactive waste. The Administrator's authority to establish these standards is embodied in section 161b. of the Atomic Energy Act of 1954, Reorganization Plan No. 3 of 1970, and section 121(a) of the Nuclear Waste Policy Act of 1982.

Section 801 builds upon this existing authority of the Administrator to set generally applicable standards and directs the Administrator to establish health-based standards for protection of the public from release or radioactive materials that may be stored or disposed of in a repository at the Yucca Mountain site. The provisions of section 801 make clear that the standards established by the authority in this section would be the only such standards for protection of the public from releases of radioactive materials as a result of the disposal of spent nuclear fuel or high-level radioactive waste in a repository at the Yucca Mountain site. Any other generally applicable standards established pursuant to the Administrator's authority under section 161b. of the Atomic Energy Act of 1954, Reorganization Plan No. 3 of 1970, and section 121(a) of the Nuclear Waste Policy Act of 1982 would not apply to the Yucca Mountain site.

The provisions adopted by the Conferees in section 801 require the Administrator to promulgate health-based standards for protection of the public from releases of radioactive materials from a repository at Yucca Mountain, based upon and consistent with the findings and recommendations of the National Academy of Sciences. These standards shall prescribe the maximum annual dose equivalent to individual members of the public from releases to the accessible environment from radioactive materials stored or disposed of in the repository. The provisions of section 801 do not mandate specific standards but rather direct the Administrator to set the standards based upon and consistent with the findings and recommendations of the National Academy of Sciences.

The Administrator is directed to contract with the National Academy of Sciences to conduct a study to provide findings and recommendations on reasonable standards for protection of the public health and safety by not later than December 31, 1993. In carrying out the study, the National Academy of Sciences is asked to address three questions: whether a health-based standard based upon doses to individual members of the public from releases to the accessible environment will provide a reasonable standard for pro-

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tection of the health and safety of the general public; whether it is reasonable to assume that a system for post-closure oversight of the repository can be developed, based upon active institutional controls, that will prevent an unreasonable risk to breaching the repository barriers or increasing the exposure of individual members of the public to radiation beyond allowable limits; and whether it is possible to make scientifically supportable predictions of the probability that the repository's engineered or geologic barriers will be breached as a result of human intrusion over a period of 10,000 years. In looking at the question of human intrusion, the Conferees believe that it is also appropriate to look at issues related to predications of the probability of natural events.

In carrying out the study, the National Academy of Sciences would not be precluded from addressing additional questions or issues related to the appropriate standards for radiation protection at Yucca Mountain beyond those that are specified. For example, the study could include an estimate of the collective dose to the general population that could result from the adoption of a health-based standard based upon doses to individual members of the public. The purpose of the listing of specific issues is not to limit the issues considered by the National Academy of Sciences but rather to attempt to focus the study on concerns that have been raised by the scientific community.

Under the provisions of section 801, the Administrator is directed to promulgate standards within one year of receipt of the findings and recommendations of the National Academy of Sciences, based upon and consistent with those recommendations. The Conferees do not intend for the National Academy of Sciences, in making its recommendations, to establish specific standards for protection of the public but rather to provide expert scientific guidance on the issues involved in establishing those standards. Under the provisions of section 801, the authority and responsibility to establish the standards, pursuant to a rulemaking, would remain with the Administrator, as is the case under existing law. The provisions of section 801 are not intended to limit the Administrator's discretion in the exercise of his authority related to public health and safety issues.

The provisions to modify its technical requirements and criteria for licensing of a repository to be consistent with the standards promulgated by the Administrator within one year of the promulgation of those standards. In modifying its technical requirements and criteria, the Nuclear Regulatory Commission (NRC) is directed to assume, to the extent consistent with the findings and recommendations of the National Academy of Sciences, that civilization will continue to exist and that post-closure oversight of the repository will continue, and to include in its technical requirements and criteria, engineered barriers to prevent human intrusion. As with the Administrator, the provisions of section 801 are not intended to limit the Commission's discretion in the exercise of its authority related to public health and safety.

The provisions of section 801 address only the standards of the Environmental Protection Agency, and comparable regulations of the Nuclear Regulatory Commission, related to protection of the public from releases of radioactive materials stored or disposed of at the Yucca Mountain site pursuant to authority under the Atomic Energy Act, Reorganization Plan No. 3 of 1970, the Nuclear Waste Policy Act of 1982, and this Act. The provisions of section 801 are not intended to affect in any way the application of any other existing laws to activities at the Yucca Mountain site.

TITLE X—REMEDIAL ACTION AND URANIUM REVITALIZATION

SUBTITLE A—REMEDIAL ACTION AT ACTIVE PROCESSING SITES

Funds made available under this program are intended to be provided for all costs that result from the disposition of byproduct material at active processing sites (subject to the limitations of Sec. 1001(b)), including groundwater remediation, treatment of contaminated soil, disposal of process wastes, removal actions, air pollution studies, mill and equipment decommissioning, site monitoring, administrative expenses, and additional expenditures required by related standards and regulations. An example of remediation costs would be cleaning up wind-blown by-product material in the vicinity of the commingled site. The availability of such funds under this program shall be considered by the Nuclear Regulatory Commission in determining the sufficiency of the financial surety arrangements that must be established by mill operators for reclamation, decontamination, and decommissioning pursuant to 10 C.F.R. Pt. 40, Appendix A (criteria 10 and 11).

TITLE XII—RENEWABLE ENERGY

Section 1202 amends P.L. 101-218, the Renewable Energy and Energy Efficiency Technology Competitiveness Act, by restructuring the former joint venture program, the management plan, and the R&D goals. The program retains as its basic goal the acceleration of the commercialization of renewable energy and energy efficiency technologies through collaboration between industry and government on a cost-shared basis.

There are two major changes. First, the technologies will be chosen for Federal support on a competitive basis, as opposed to the original statute, which mandated joint ventures in specific technology areas. Second, the Secretary has been given wider latitude to choose financial mechanisms, including interest rate buydowns, to use in implementing the demonstration and commercial application program. The Secretary may utilize a financial intermediary for advice or assistance in the implementation of the program.

Elements of the revised program are modeled on the Clean Coal Technology program. The Secretary is directed to issue a solicitation and evaluate and select projects for financial assistance on the basis of DOE-developed criteria.

Section 1210. It is the understanding of the conference committee that the authorities established under Section 1210(a) will be implemented only when the monies authorized under Section 1210(b) are appropriated.

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United States - Federal

TAB 8

Report on the Study of the Tax and Rate Treatment of Renewable Energy Projects Issued Pursuant to Section 1205 of the Energy Policy Act of 1992

DE94-005 693

REPORT ON THE STUDY OF THE TAX AND RATE TREATMENT OF RENEWABLE ENERGY PROJECTS

OAK RIDGE NATIONAL LABORATORY
OAK RIDGE, TN

DEC 93

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
NTIS

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REPORT ON THE STUDY OF THE TAX AND RATE TREATMENT OF RENEWABLE ENERGY PROJECTS

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PREFACE

Although this study was conducted at Oak Ridge National Laboratory (ORNL), it was a collaborative effort between the authors at ORNL and staff of the Office of Policy, Planning, and Program Evaluation (PPPE) of the U.S. Department of Energy (DOE) and members of the National Association of Regulatory Utility Commissioners (NARUC). Extensive discussions were held on the scope of the study, assumptions used to characterize the generating technologies, modeling scenarios, discussions of results, and the like over a six-month period.

Paul Carrier led the effort at DOE. Six state commissioners were represented: (1) Commissioner Elizabeth Paine (Maine), Commissioner Edward M. Meyers (District of Columbia), Commissioner Ralph Nelson (Idaho), Commissioner J. Terry Deason (Florida), Commissioner James Byrne (Utah), and Chairman Richard Cowart (Vermont). Doug Bauer, the head of the Washington office of ORNL's Energy Division and Russ Profozich of DOE's PPPE Office, actively participated in the discussions over the course of the project.

Many people reviewed early drafts of this study and provided very useful comments as the document evolved over time. However, we would especially like to thank Dan Alpert of Sandia National Laboratories (temporarily assigned to DOE Washington at the time of his reviews) and Eric Hirst of Oak Ridge National Laboratory who provided 'technical reviews' of the document.

Finally, although an attempt was made to include all of the important input assumptions, model documentation, and simulation results in this document, some were excluded to hold it to a manageable length. All of the information, however, is available from the authors upon request.

EXECUTIVE SUMMARY

S.1. BACKGROUND

This study was conducted in response to Section 1205 of the Energy Policy Act of 1992 (EPACT), requiring the U.S. Department of Energy in conjunction with state regulatory commissions to determine if conventional tax measures and ratemaking procedures provide economic barriers to or incentives for the adoption of renewable electric generating plants compared to conventional ones. For this study, we defined barriers and incentives in terms of financial criteria used by investor-owned utilities (IOUs) and nonutility electricity generators (NUGs) when making decisions on technologies for new generating plants. For IOUs, the major criterion used was the levelized cost of producing power over the useful life of the technology. For NUGs, the major criterion used was the internal rate of return.

Clearly, there are many factors outside the scope of this study that relate to the decisionmaking process of IOUs and NUGs. This study to determine barriers and incentives does not attempt to determine which technologies would most likely be adopted by IOUs and NUGs. Technologies are only cost (in)effective relative to a given power system and its set of internal and external conditions. Other technology-related factors such as availability, dispatchability, diversity, and reliability of generating alternatives are also considered in the decisionmaking process used by IOUs and NUGs. The results of this study show only the relative impact of certain tax measures and ratemaking procedures on financial criteria that IOUs and NUGs use as inputs to make technology-adoption decisions. Where these tax measures and ratemaking procedures provide incentives for an alternative, they increase the likelihood that the alternative will be selected by IOUs or NUGs when making generating-resource decisions.

In quantifying the parameters of the seven renewable and four conventional generating options studied, we used today's 'conventional wisdom' on the values of variables defining the technologies. We did not speculate on the technological evolution of the generating options, consequent changes in their costs, and changes in their attractiveness to IOUs and NUGs in the future.

Consistent with the direction provided by the legislation, this study was limited to the portions of the electric power industry that make decisions on generating technologies. We did not investigate barriers or incentives that may result from tax policies affecting other segments of the fuel cycle, such as incentives for production of fossil fuels.[1] It was also not possible to quantify the ratemaking treatment of risks. For example, the ratemaking procedure of passing through the costs of fuel to customers removes the risk of unexpected fuel price fluctuations for decisionmakers selecting conventional technologies. The structure of financial, labor, materials, fuel, and

[1] An analysis of the total fuel cycle was not included in this study for two reasons. First, Section 1205 clearly states that the study is to evaluate barriers and incentives for renewable power plants. A second reason is that Section 3015 of EPACT requires that the National Academy of Sciences conduct a study on energy subsidies.

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purchased power contracts are also beyond the scope of this study. Finally, the transmission and distribution of electric power was not studied.

S.2. CONCLUSIONS

The study results show that tax measures and ratemaking procedures are both barriers and incentives for renewable energy power plants, depending on the measure or procedure and whether the decisionmaker is an IOU or a NUG. More specifically, for the taxes and ratemaking procedures that were modeled, the study shows:

- Federal income tax laws provide incentives for IOUs to invest in solar, wind, geothermal, and dedicated-plantation biomass technologies. These incentives result from short tax depreciation lives and the recently enacted 1.5¢/kWh production tax credit for dedicated-plantation biomass and wind technologies.

- In addition to short tax depreciation lives and the production tax credit, the investment tax credit for solar and geothermal technologies also provides incentives for a NUG to adopt renewable technologies if the NUG is not subject to the alternative minimum tax (AMT).

- If a NUG is subject to the AMT, the NUG is not able to take full advantage of the federal tax incentives for renewables and federal tax laws become a barrier to the adoption of renewable technologies.

- Local property taxes are barriers to the adoption of hydro, solar, and wind technologies. This conclusion is robust under different assumptions about the bases used for calculating property taxes.

- For the ratemaking procedures for IOUs that we modeled, tax normalization is an incentive for hydro, solar, and wind technologies because this procedure allows utilities to use short tax depreciation lives.

- Although we were not able to model the procedure of passing through the risk of fuel-price fluctuations to ratepayers, this ratemaking procedure generally is a barrier to the adoption of renewable technologies.

1. INTRODUCTION AND SUMMARY

1.1. PURPOSE OF THE STUDY

This study was conducted in response to the requirements of Section 1205 of the Energy Policy Act of 1992 (EPACT), which states:

> The Secretary (of Energy), in conjunction with State regulatory commissions, shall undertake a study to determine if conventional taxation and ratemaking procedures result in economic barriers to or incentives for renewable energy power plants compared to conventional power plants.

The purpose of the study, therefore, is *not* to compare the cost-effectiveness of different types of renewable and conventional electric generating plants. Rather, it is to determine the relative impact of conventional ratemaking and taxation procedures on the selection of renewable power plants compared to conventional ones.

To make this determination, we quantify the technical and financial parameters of renewable and conventional electric generating technologies, and hold them fixed throughout the study. Then, we vary taxation and ratemaking procedures to determine their effects on the financial criteria that investor-owned electric utilities (IOUs) and nonutility electricity generators (NUGs) use to make technology-adoption decisions. In the planning process of a typical utility, the opposite is usually the case. That is, utilities typically hold ratemaking and taxation procedures constant and look for the least-cost mix of resources, varying the values of engineering and financial parameters of generating plants in the process.

1.2. SCOPE OF THE STUDY

The enabling legislation for this study also defines its scope. That is, the legislation requires that we address "barriers to or incentives for renewable energy power plants compared to conventional power plants." This suggests, first, that we limit the study to portions of the electric power industry that make decisions on the adoption of generating technologies and, second, that we focus on financial criteria that decisionmakers use to adopt technologies to see if there are tax measures or ratemaking procedures that provide barriers and/or incentives for the selection of generating technologies.

In Figure 1.1, we indicate in shaded areas the position of these decisionmakers in the context of the extended U.S. electric power industry.[1] The extended industry consists of (1) fuel suppliers for electricity generation; (2) financing, labor, materials, fuel, and purchased power contracted for by IOUs and NUGs to generate power; (3) the electric power industry, including IOUs, state and municipally owned utilities, federal power projects, and rural electric cooperatives; and (4) export, wholesale and end-use

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[1]For the sake of clarity in Figure 1.1, we include the total set of inputs used to produce electricity for IOUs only. We excluded these inputs for NUGs to simplify the diagram.

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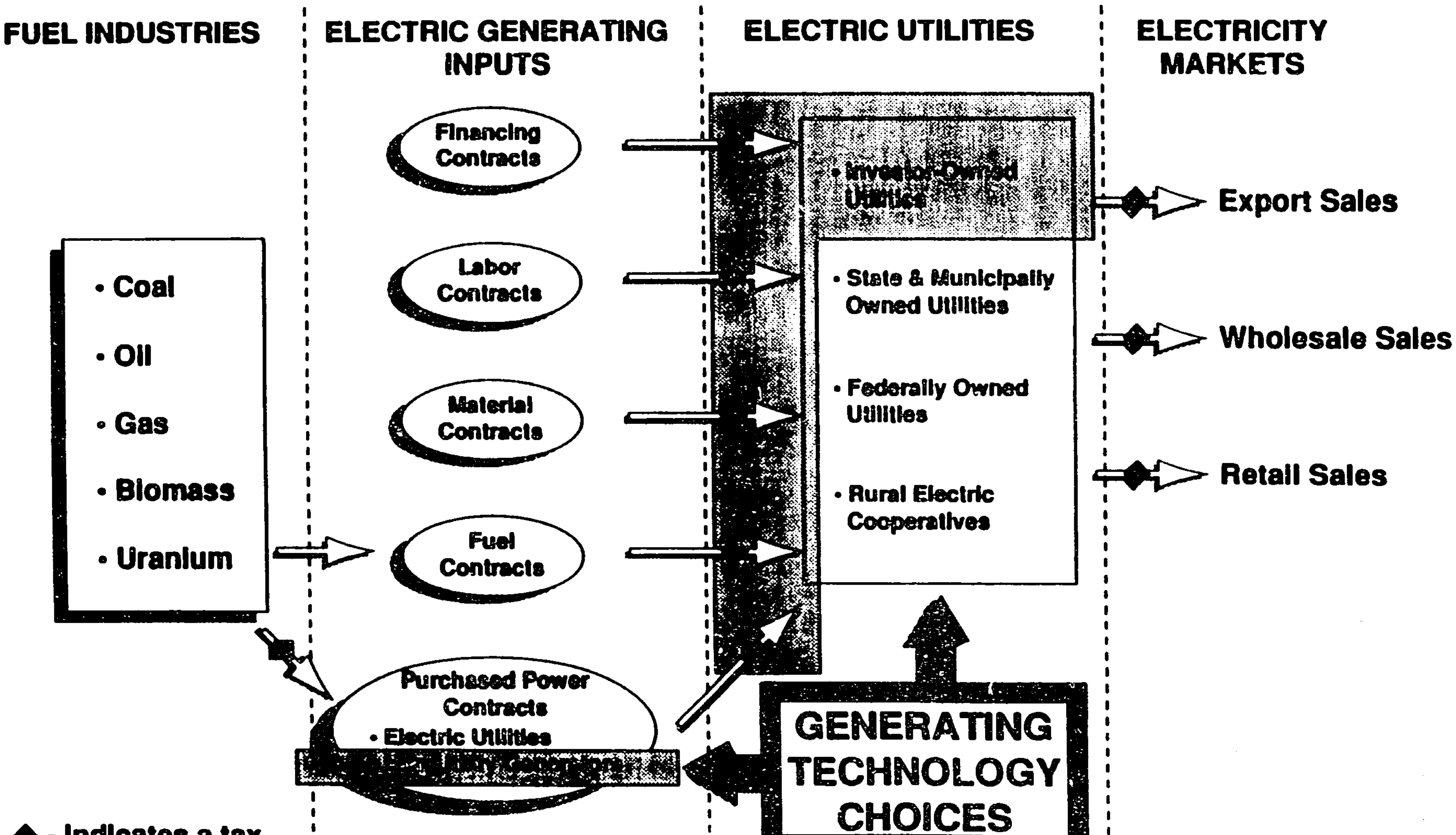
Figure 1.1

Schematic Representation of the U.S. Electric Utility Industry



◆ - Indicates a tax

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electricity sales. As indicated by the shaded areas of Figure 1.1, the applicable decisionmakers under Section 1205 of EPACT are IOUs and NUGs. The latter consist of qualifying facilities (QFs) and nonqualifying facilities (non-QFs). In 1991, QFs accounted for 75 percent of the electric generating capacity of NUGs (Energy Information Administration, 1993c).[2]

As Figure 1.1 indicates, the scope of the study defined by EPACT's Section 1205 means that we do not consider in depth four other important features of the extended U.S. electric power industry:

- the entire fuel cycles of the energy used to produce electric power;
- the structure of the financial, labor, materials, fuel, and purchased-power contracts entered into by IOUs and NUGs;
- utilities other than those owned by the private sector (i.e., IOUs); and
- the transmission and distribution of electricity beyond the busbar (i.e., export, wholesale, and retail sales).

However, as indicated in Figure 1.1, we do include the sales and labor taxes incurred by IOUs and NUGs in constructing generating facilities and running them. We do not include those same types of taxes incurred by purchasers of electric power beyond the busbar. We discuss these four portions of the extended industry in turn:

Clearly, historical and current policy measures that have shaped the development of electric generating technologies and energy industries upstream from the production of electric power are important factors in explaining the adoption of electric generating technologies by both IOUs and NUGs today and, as such, would be interesting topics of study. For example, development of some energy forms have been subsidized over the years, giving them a competitive advantage in today's marketplace.[3] Also, an examination of the entire fuel cycles of certain technologies suggest that some have fared better from policy initiatives than others.[4] However, these issues are beyond the scope of Section 1205 of EPACT.

Second, the management of electric utilities enter into many different types of contracts related to financing, labor matters, material purchases, energy requirements, and purchased power. The structure of some of these contracts may provide

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[2]In 1991, NUGs owned 48,200 MW of capacity. Of this amount, QFs owned 75 percent of it (i.e, cogenerators owned 59 percent and small power producers using renewable energy forms 16 percent); non-QFs owned the remainder (cogenerators 14 percent and independent power producers and other commercial/industrial establishments 11 percent). In 1992, EPACT created the exempt wholesale generator (EWG), another type of non-QF. EWGs differ from QFs in that (1) they are not required to meet PURPA's cogeneration or renewable fuels limitations and (2) utilities are not required to purchase power from EWGs.

[3]For recent studies on energy subsidies, see The Alliance to Save Energy (1993) and Energy Information Administration (1992). Also, Section 3015 of EPACT requires that the National Academy of Sciences conduct a study on energy subsidies and report to Congress by April 24, 1994.

[4]See, for example, Oak Ridge National Laboratory and Resources for the Future (1992).

(dis)incentives for entering into them. For example, the structure of a long-term fuel-supply contract may not be appealing to an electric utility for any number of reasons, including escalation costs over time, fuel delivery dates, and the like. Or, the structure of a purchased-power contract may provide (dis)incentives for an electric utility to purchase power from a given source.[5] Again, while contractual issues are important in the electric power industry, the structure of contracts is well beyond the scope of EPACT's Section 1205.

Third, the U.S. electric power industry consists of IOUs and, from Figure 1.1, different types of publicly owned systems, including state and municipal utilities, federal power projects (five power marketing agencies and the Tennessee Valley Authority), and rural electric cooperatives.[6] Although the investor-owned segment accounts for nearly 80 percent of the industry in terms of sales and investment, publicly owned systems also make technology-adoption decisions. We focus here on IOUs because, for one, publicly owned systems are not subject to federal income taxes and, therefore, federal tax policy--by definition--is neither an incentive nor barrier to the adoption of renewable technologies compared to conventional ones. Also, even in the minority of cases in which publicly owned utilities are regulated by state commissions, they are not generally subject to rate-of-return regulation as are IOUs. Therefore, ratemaking barriers and incentives do not exist for publicly owned electric utilities as they do for IOUs.[7]

Finally, in this study, we consider electric power generation up to the busbar. No attempt is made to look beyond electric power generation at, for example, incentives and barriers to the use of the solar photovoltaic technology on transmission systems to enhance reliability. And, from Figure 1.1, because electric utilities do not incur the taxes that may be applied to export, wholesale, and retail electricity sales, these taxes are also not considered a barrier to or incentive for adoption of renewable and conventional generating technologies.

1.3. APPROACH USED IN THE STUDY

To conduct this study, we first quantified the capital and operating parameters of 11 electric generating alternatives, seven renewable and four conventional. The 11 options are:

- biomass with dedicated-plantation feedstock,
- biomass with waste-wood feedstock
- geothermal

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[5]For a discussion of the types of power contracts negotiated by NUGs, see Edison Electric Institute (1992).

[6]Technically, rural electric cooperatives are not publicly owned utilities. However, because they are not subject to federal income taxes and their capital costs are subsidized, they are generally treated as publicly owned (Hill, 1988).

[7]For a more lengthy discussion of these tax and ratemaking issues, see Hill (1988).

- hydroelectric
- solar-photovoltaic
- solar-thermal
- wind
- coal
- combined cycle
- combustion turbine
- nuclear

Each of the alternatives was assigned a hypothetical work load in a power system, defined by its capacity factor. For example, the biomass and geothermal renewable options are base-load plants and, therefore, given high capacity factors. On the other hand, a combustion turbine unit is a peaking unit and, therefore, given a low capacity factor. These issues are discussed fully in Section 3. The 11 technologies--and their associated capital and operating costs--are technologically and financially feasible at the present time. That is, we made no attempt to speculate on expected changes in the costs of the technologies in the future. Also, all of the values defining the parameters are in constant 1991 dollars as is the entire analysis.[8] However, as shown in Section 5.4 in which the results of our sensitivity studies are presented, conducting the analysis in current dollars has no bearing on the conclusions.

Second, we constructed a financial regulatory model of the electric utility industry that can handle ratemaking procedures and tax measures used in the U.S. electric utility industry, including federal, state, and local taxes, the treatment of construction work in progress, normalized vs. flow-through tax accounting, and fuel adjustment clauses. The model is documented in Appendix A.

Third, we defined decisionmaking criteria used to evaluate generating technologies. Because we examine incentives and barriers for both IOUs and NUGs, we use two sets of decisionmaking criteria. For IOUs, we use primarily the levelized cost of producing electricity from each of the 11 alternatives and, secondarily, their internal rate of return. We do not look at interactions among the technologies within a given power delivery system. Rather, we use individual project analysis of the type that would be used to develop screening curves in electric-utility planning. Recognizing that NUGs are not subject to rate-of-return regulation as are IOUs, we use the total internal rate of return (IRR) and IRR-equity as measures of financial attractiveness for NUGs.

Under certain circumstances, it would be more appropriate to use IRR-equity as the primary financial criterion for NUGs. This is especially true in analyzing individual projects in which detailed financing information is known. Because we conducted this study at an aggregated level, financial returns are calculated on the basis of a 'generic project.' In real-world applications in which the relationships among project type, credit-worthiness of the investor, leveraging of debt, and repayment schedules are clearly defined, values of IRR-equity more accurately reflect the true return to equity shareholders. In this study, the values of IRR-equity are included for information purposes

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[8]This is consistent with the approach recommended by the Electric Power Research Institute (1989).

only.[9]

Fourth, we define a reference case for each of the 11 technologies and two ownership types. In the reference case, we attempt to capture as closely as possible the current tax measures and ratemaking procedures for IOUs and taxes for NUGs. In the alternative scenarios, we estimate the effects of these taxes and procedures, include effects of the following:

- all taxes,
- local property taxes,
- taxes on construction and operating inputs,
- state income taxes,
- federal income taxes,
- accelerated federal tax depreciation under the modified accelerated cost recovery system provided for by the Tax Reform Act of 1986,
- federal production and investment tax credits for various renewable technologies,
- an alternative minimum tax for NUGs,
- including construction work in progress (CWIP) in the rate base for IOUs,
- flow-through tax accounting for IOUs, and
- a fuel adjustment clause for IOUs.

Fifth, using the financial regulatory model, we simulated the reference and alternative scenarios for both IOUs and NUGs. The results for the alternative scenarios were then indexed to the reference case. Comparing results for the scenarios indicates the direction and extent to which tax measures and ratemaking procedures affect the values of the decisionmaking criteria and, hence, whether or not the measures and procedures are barriers or incentives for individual technologies. For example, comparing values of levelized cost for the case in which all construction work in process is allowed in the rate base and the reference case in which no CWIP is allowed shows whether or not the ratemaking treatment of CWIP is a barrier or incentive for adoption of a technology by an IOU.

Finally, we used the ratios calculated in the fifth step to define barriers and incentives for renewable technologies compared with conventional ones. To accomplish this, we examined the ratios of each renewable technology to see if the ratios are *significantly different* from the corresponding ones for conventional technologies. Significance was defined in terms of a five-percent threshhold in comparing the ratios for a renewable technology to the average value of the ratios of conventional technologies for each of the tax measures and ratemaking procedures. For IOUs, if the value of the ratio for a renewable technology was more than five percent less than the corresponding average value for conventional technologies, the measure or procedure is an 'incentive'

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[9]The results using total IRR and IRR-equity are very similar and major conclusions of the report would not change if IRR-equity were used as the sole decisionmaking criterion. The interested reader should review the results in Appendix B for confirmation of this conclusion.

for the adoption of that renewable technology compared to conventional ones. Similarly, if the value of the ratio for a renewable technology is more than five percent greater than the corresponding average value for conventional technologies, the measure or procedure is a 'barrier' to adoption of that renewable technology compared to conventional ones. Because the decisionmaking criterion for NUGs is the internal rate of return rather than levelized cost, the percentage differences from the average value for conventional technologies are reversed in determining barriers and incentives for renewable technologies.

1.4. OVERVIEW OF RESULTS

1.4.1. Effects on Investor-Owned Electric Utilities

The data in Table 1.1 are a summary of the tax simulation results for IOUs. All of the data are indexed to the reference case which was designed to be 'representative' of the tax and ratemaking situations of a typical IOU. Specifically, (1) federal taxes on income are 35 percent and various federal tax incentives such as accelerated depreciation and investment and production tax credits are included; (2) state taxes on income are six percent; (3) local taxes on property (valued on the basis of net book value) are three percent; (4) no CWIP is allowed in the rate base; and (5) the benefits of accelerated tax depreciation are normalized.

By indexing the results of the alternative scenarios to the reference case, we put the data in Table 1.1 on a ratio basis, with values greater than 1.00 representing increases in costs as a result of the various tax measures and values less than 1.00 representing decreases. Therefore, using our definition of barriers and incentives, the 0.97 'effect of all taxes' for dedicated-plantation biomass systems indicates that the taxes imposed on these systems--i.e., the sum of local, state, and federal taxes--are incentives to adopting that technology because these taxes decrease the levelized cost of producing electricity. On the other hand, the 1.19 result for waste-wood biomass systems indicates that imposing these same taxes on that technology is a barrier to adopting it by IOUs because the taxes increase its levelized cost. Of course, it is these kind of results--and, more important, their causes-- which are the subject of this study.

The results presented in Table 1.1 are disaggregated in Section 5. That is, many more simulations for each category of taxes were run than are presented in the summary data of Table 1.1. In Section 5.2.1, we present and discuss federal taxes in greater detail. In Section 5.2.2, we present and interpret results using different bases for calculating property taxes. Finally, in Section 5.2.3, we discuss input taxes at greater length.

As indicated in Table 1.1, local, state, and federal taxes and credits taken together are a barrier to adopting five of the seven renewable and all conventional technologies. The largest barrier is provided hydro in which taxes increase the levelized cost by 40 percent over the reference case. Taxes are an incentive for dedicated-plantation biomass and wind technologies because of the financial advantages of the 1.5¢/kWh production tax credit which override all other tax effects. This will be discussed in greater detail in Sections 5.2.1 for IOUs and 6.2.1 for NUGs.

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Table 1.1
Summary of Tax Effects on Levelized Costs, Investor-Owned Utilities

(Cost Ratio of Case with Taxes to Case Without Taxes)

Generating Type	Effect of Including All Taxes and Credits[a]	Effect of Including Property Taxes	Effect of Including Input Taxes	Effect of Including State Income Taxes	Effect of Including Federal Taxes and Credits
Renewable					
Biomass-Plantation	0.97	1.09	1.07	0.99	0.85
Biomass-Waste	1.19	1.08	1.06	1.01	1.03
Geothermal	1.16	1.11	1.07	1.00	0.98
Hydro	1.40	1.24	1.07	1.01	1.04
Solar-Photovoltaic	1.27	1.27	1.07	0.99	0.95
Solar-Thermal	1.24	1.23	1.07	0.99	0.95
Wind	0.91	1.31	1.10	0.97	0.71
Conventional					
Coal	1.22	1.09	1.07	1.01	1.04
Combined Cycle	1.18	1.07	1.06	1.00	1.03
Combustion Turbine	1.18	1.09	1.06	1.00	1.02
Nuclear	1.20	1.09	1.07	1.00	1.03

Source: Section 5 in Text

Ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives.

[a] Because of multiple effects, individual tax effects cannot be summed to obtain

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Property taxes, based on the net book value of property, plant, and equipment, increase the levelized cost of all technologies. Therefore, property taxes are a barrier for the adoption of both conventional and renewable technologies. Looking at individual technologies, property taxes increase the levelized costs of renewable technologies more than conventional ones, especially for hydro, solar, and wind. The reason is that these technologies are more capital intensive--i.e., higher capital-operating ratios (See Figure 5.1 in Section 5).

Taxes on inputs used to construct generating plants (i.e., sales taxes on energy and materials, and payroll taxes on labor) and run them (i.e., sales taxes on operation and maintenance expenses and payroll taxes on labor) affect renewable and conventional technologies in a similar manner and to generally the same degree. Because they increase their levelized costs, input taxes are barriers to adopting all technologies.

State income taxes have a nominal effect on all technologies. They are incorporated in a manner similar to federal income taxes (i.e., same tax-book depreciation lives, normalized accounting for IOUs), but their effects are less than federal income taxes because a six-percent rate rather than a 35-percent rate is used.

Federal income taxes have very different effects on conventional and renewable technologies. For all conventional technologies, the effect of federal income taxes is to increase their levelized cost and, therefore, pose a barrier for adopting the technologies. With the exception of waste biomass and hydro, this is not the case for renewable technologies. Here, the effect of federal taxes is to reduce the levelized cost of the technologies and, therefore, provide an incentive for their adoption. The reasons are the certain provisions of the federal tax code allowing greater accelerated depreciation rates for most renewable technologies than conventional ones, an investment tax credit for solar and geothermal technologies, and a 1.5¢/kWh production credit for dedicated-plantation biomass and wind technologies. These effects are discussed in greater detail in the context of federal taxes in Sections 5 and 6.

In Table 1.2, we summarize the simulation results for ratemaking procedures used by IOUs. The reference case for the results in Table 1.2 is the same as that used for Table 1.1. The ratios also have the same interpretation as Table 1.1.

Allowing all CWIP in the rate base has a nominal effect on the levelized costs of all generating technologies, renewable and conventional. The major effect of CWIP is on cash flow, and not the levelized cost of the technologies. This is illustrated in Figure 5.6 in Section 5. Similar to the effects of allowing CWIP in the rate base, lagging the time period over which fuel costs are allowed for ratemaking purposes has a nominal effect on the levelized cost of the technologies.

Flowing the tax benefits of accelerated depreciation directly to ratepayers in the year in which the benefits are received for tax purposes--rather than normalizing them and creating a deferred reserve--increases the levelized costs of all technologies because current tax law also requires that tax depreciation lives increase when flow-through tax accounting is used. Normalized vs. flow-through accounting is discussed in greater detail in Section 4.

Table 1.2
Summary of Ratemaking Effects on Levelized Cost
Investor-Owned Utilities
(Cost Ratio of Case with Ratemaking Procedure to Case Without)

Generating Type	Effect of Not Including CWIP in Rate Base	Effect of Normalizing Taxes in Rate Base	Effect of Automat Fuel Adjustment
Renewable			
Biomass-Plantation	1.00	0.98	1.00
Biomass-Waste	1.00	0.98	1.00
Geothermal	1.00	0.94	1.00
Hydro	1.00	0.90	1.00
Solar-Photovoltaic	1.00	0.89	1.00
Solar-Thermal	1.00	0.90	1.00
Wind	1.00	0.89	1.00
Conventional			
Coal	1.00	0.98	1.00
Combined Cycle	1.00	0.98	1.00
Combustion Turbine	1.00	0.98	1.00
Nuclear	1.00	1.03	1.00

Source: Section 5 in Text

1.4.2. Effects on Nonutility Generators

Summary results for NUGs are presented in Table 1.3. For tax measures, reference case for NUGs is the same as that for IOUs in Tables 1.1 and 1.2. Beca NUGs are not subject to the ratemaking procedures that IOUs are, CWIP and normalization are not applicable and not included in the reference case or any of scenarios. Also, because the decisionmaking criterion used as the basis for the res presented in Table 1.3 is the internal rate of return (IRR), values greater than represent incentives for the technology, while values less than 1.00 are barriers–dir opposite to the interpretation of Tables 1.1 and 1.2.

With minor exceptions, the taxation barriers and incentives for IOUs in Table for property taxes, input taxes, state taxes, and federal taxes are similar to those for N shown in Table 1.3. The main difference between IOUs and NUGs is the effect of t

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Table 1.3
Summary of Tax Effects on Internal Rate of Return, Nonutility Generators

(Ratio of IRR of Case with Taxes to Case Without Taxes)

Generating Type	Effect of Including All Taxes and Credits [a]	Effect of Including Property Taxes	Effect of Including Input Taxes	Effect of Including State Income Taxes	Effect of Including Federal Taxes and Credits	Effect of Including Alternative Minimum Tax
Renewable						
Biomass-Plantation	1.53	0.81	0.83	1.05	5.58	0.68
Biomass-Waste	0.71	0.82	0.86	1.01	1.06	0.77
Geothermal	0.82	0.81	0.87	1.02	1.29	0.75
Hydro	0.71	0.83	0.93	1.00	0.99	0.91
Solar-Photovoltaic	0.90	0.79	0.92	1.02	1.38	0.71
Solar-Thermal	0.89	0.79	0.91	1.02	1.38	0.71
Wind	1.35	0.75	0.88	1.06	3.58	0.65
Conventional						
Coal	0.64	0.84	0.87	0.99	0.93	0.97
Combined Cycle	0.56	0.80	0.83	0.99	0.90	0.98
Combustion Turbine	0.56	0.78	0.83	0.99	0.96	0.94
Nuclear	0.67	0.85	0.87	0.99	0.96	0.94

Source: Section 6 in Text

Ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

[a] Because of multiple effects, individual tax effects cannot be summed to obtain the total effect.

AMT. For noncorporate and corporate entities to which the AMT applies, the AMT is a significant barrier to adoption of all technologies--but primarily renewable technologies which benefit to a larger extent than conventional ones from certain provisions of the federal tax code. From Table 1.3, the federal income tax and its special provisions increase the IRR for dedicated-plantation biomass systems by more than 400 percent from the reference case. If the corporate entity building the plant were subject to the AMT, however, those federal tax advantages would be totally lost.

1.4.3. Barriers To and Incentives For Renewable Technologies

The ratios in Tables 1.1 through 1.3 indicate how tax measures and ratemaking procedures affect the decisionmaking criteria used by IOUs and NUGs in evaluating individual technologies. We use that data in this section to determine the types of taxes and ratemaking procedures that are barriers to or incentives for renewable technologies compared to conventional ones. Concisely, a tax or rate procedure is an incentive for the adoption of a renewable technology by IOUs if its ratio in Table 1.1 or 1.2 is more than five percent less than the corresponding average value for all conventional ones. It is a barrier if the ratio is more than five percent greater. For NUGs, the direction of change from the average value of conventionals is reversed for barriers and incentives. This is discussed in greater detail in Section 7.3.

The results on barriers and incentives for renewable technologies are summarized in Tables 1.4 and 1.5 for IOUs and NUGs, respectively. The results show that tax measures and ratemaking procedures are both barriers and incentives, depending on the measure or procedure and whether the decisionmaker is an IOU or a NUG. More specifically, five important conclusions emerge from the data in Tables 1.4 and 1.5.

First, certain federal income tax laws provide incentives for IOUs to invest in most renewable technologies. Short tax depreciation lives provide incentives for solar, wind, and geothermal technologies. Additional incentives are provided by the investment tax credit for solar and geothermal technologies and a 1.5¢/kWh production tax credit for dedicated-plantation biomass and wind technologies.

Second, short tax depreciation lives, the investment tax credit, and the production tax credit also provide incentives to a NUG to adopt renewable technologies if the NUG is not subject to the alternative minimum tax (AMT).

Third, if a NUG is subject to the AMT, the NUG is not able to take full advantage of the federal tax incentives for renewables and, therefore, the federal tax laws become a barrier to the adoption of these technologies.

Fourth, local property taxes are barriers to the adoption of capital-intensive renewable technologies. This conclusion is robust under different assumptions about the bases used for calculating property taxes.

Fifth, for the ratemaking procedures for IOUs that we modeled--automatic fuel adjustment clauses vs. adjusting for fuel costs in rate cases, the inclusion in the rate base of construction work in progress (CWIP) vs. the calculation of allowance for funds used

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Table 1.4
Summary of Barriers To and Incentives For Renewable Technologies
Comparison With Conventional Technologies
Investor-Owned Utilities

Measure/ Procedure	Biomass Plantation	Biomass Waste	Geothermal	Hydro	Solar PV	Solar Thermal	Wind
Taxation Effects:							
All Taxes	I	-	-	B	B	-	I
Local Property Taxes	-	-	-	B	B	B	B
Taxes on Inputs	-	-	-	-	-	-	-
State Income Taxes	-	-	-	-	-	-	-
Federal Income Taxes[a]	I	-	I	-	I	I	I
Accelerated Depreciation[b]	-	-	I	I	I	I	I
Federal Tax Credits[c]	I	NA	NA	NA	NA	NA	I
Ratemaking Effects:							
No CWIP in the Rate Base	-	-	-	-	-	-	-
Tax Normalization	-	-	-	I	I	I	I
Fuel Adjustment Clauses	-	-	-	-	-	-	-

SOURCE: Table 7.1 in Section 7.3.

A 'B' indicates that the tax measure or ratemaking procedure is a barrier to adopting the technology based on comparison with conventional technologies. An 'I' indicates that the tax measure or ratemaking procedure is an incentive for adopting the technology based on comparison with conventional technologies. An 'NA' indicates that the measure is not applicable to the technology. An '-' indicates that the measure or procedure is applicable, but the value of the ratio is within ± five percent of the average for conventional technologies.

[a]Includes the effects of all federal income taxes, including accelerated depreciation, and federal production and investment tax credits.

[b]Includes the effects of accelerated depreciation exclusively.

[c]Includes the effects of federal production and investment tax credits exclusively.

during construction (AFUDC), and normalization vs. flowing taxes through the rate base--the automatic fuel adjustment clause and CWIP have minimal effect on the selection of generation resources. Normalization is an incentive for hydro, solar, and wind technologies.

1.5. REMAINDER OF THE REPORT

The remainder of the report is divided into six sections with three supporting,

Table 1.5
Summary of Barriers To and Incentives For Renewable Technologies
Comparison With Conventional Technologies
Nonutility Generators

Measure/ Procedure	Biomass Plantation	Biomass Waste	Geothermal	Hydro	Solar PV	Solar Thermal	Wind
All Taxes	I	I	I	I	I	I	I
Local Property Taxes	-	-	-	-	-	-	B
Taxes on Inputs	-	-	-	I	I	I	-
State Income Taxes	I	-	-	-	-	-	I
Federal Income Taxes[a]	I	I	I	I	I	I	I
Accelerated Depreciation[b]	I	I	I	-	I	I	I
Federal Tax Credits[c]	I	NA	I	NA	I	I	I
Alternative Minimum Tax[d]	B	B	B	B	B	B	B

SOURCE: Table 7.2 in Section 7.3.

A 'B' indicates that the tax measure or ratemaking procedure is a barrier to adopting the technology based on comparison with conventional technologies. An 'I' indicates that the tax measure or ratemaking procedure is an incentive for adopting the technology based on comparison with conventional technologies. An 'NA' indicates that the measure is not applicable to the technology. An '-' indicates that the measure or procedure is applicable, but the value of the ratio is within ± five percent of the average for conventional technologies.

[a]Includes the effects of all federal income taxes, including accelerated depreciation, and federal production and investment tax credits.

[b]Includes the effects of accelerated depreciation exclusively.

[c]Includes the effects of federal production and investment tax credits exclusively.

[d]Includes the effects of the alternative minimum tax.

technical appendices. In Section 2, we discuss differences between individual project analysis of the type conducted in this study and system-wide, electric-utility planning. Integrated resource planning is seen as the latest method in the evolution of electric-utility planning. In Section 3, we quantify the technical cost and engineering parameters of the seven renewable and four conventional electric generating technologies considered in the study, along with the time path of construction expenditures for those technologies and assumptions about the real cost of fuel.

In Sections 4 through 6, we present the detailed results of the study. In Section 4, the simulation scenarios are defined in the context of existing taxation procedures for IOUs and NUGs and ratemaking procedures for IOUs. Actual simulation results and their interpretation for IOUs and NUGs are presented in Sections 5 and 6, respectively. A summary of all of the results is followed by a discussion of the key findings.

A synthesis of the study and its conclusions are presented in Section 7. In this section, we determine the taxation and ratemaking barriers and incentives for adopting renewable technologies compared to conventional ones and place those results in the context of the process of electric-utility decisionmaking, risk, and public policy toward conventional and renewable technologies.

In Appendices A, B, and C, we provide technical details on both inputs and outputs of the study. The model used to simulate the taxation and ratemaking scenarios is described in Appendix A. Results of all the simulations are provided in more detail in Appendix B. The raw data used to determine whether or not a tax or ratemaking procedure is a relative barrier to or incentive for renewable technologies are presented in Appendix C.

2. DECISIONMAKING CRITERIA AND RESOURCE SELECTION

2.1. INDIVIDUAL PROJECT ANALYSIS

In this study, conventional and renewable technologies were evaluated individually. Values were assigned to key parameters (to be discussed in Section 3) with no interaction allowed between generating alternatives. Therefore, the amount of time that the technologies are used during the course of a year (i.e., their capacity factors) are not based on system optimization, but were predetermined and provided from published sources. For example, the relative costs of fuel inputs did not determine if a technology should be adopted or the amount of time it was used during a year. Rather, the running rate was determined exogenously.

2.2. SYSTEM PLANNING

In real-world electric-utility planning, of course, much more sophisticated techniques are used to evaluate electric generating alternatives. Historically, capacity expansion modeling has allowed utilities to trade off technology characteristics based on peak-load projections, projected load duration curves, fuel price forecasts, and other characteristics of their power delivery systems. The degree of sophistication depends on the goals and resources of the utility. An approach that has the capability to

- determine an optimal mix of resources,
- characterize demand for 8,760 hours in every year of the planning horizon,
- determine the variable costs of employing supply-side resources,
- simulate the financial performance of the utility, and
- include uncertainties in resource selection

tends to be very large and complex with significant data requirements.

Therefore, the alternatives were evaluated under "laboratory conditions." That is, no attempt was made to emulate a utility's entire planning process. That process would normally include uncertainty and financial analyses of the type discussed above in addition to the 'screening curve' approach used in this study. If uncertainty and financial analyses were conducted, it could lead to final resource portfolios different from those suggested by the analysis here.

2.3. EFFECTS OF INTEGRATED RESOURCE PLANNING

The integrated resource planning (IRP) process complicates utility planning even more. In the IRP process, demand-side management (DSM) resources are placed on an equal footing with both conventional and renewable electric generating alternatives. The process is complicated by the different fundamental characteristics of demand and supply resources because they have different economic and reliability attributes. For example, DSM programs such as those used for load management during peak summer months are not available throughout the course of a year and do not have the same reliability characteristics as renewable and conventional generating alternatives.

The importance of IRP in the selection of resources by electric utilities is that utilities now have more options to choose from, more alternatives 'competing' to satisfy projected load and energy requirements. By all accounts, the process is expected to result in the selection of more DSM resources--at the expense of renewable and conventional supply. It is expected, for example, that DSM resources will provide as much as 30 percent of the *incremental* capacity needs from 1990 to 2000 in the United States (Schweitzer, Hirst, and Hill, 1991).

In some IRP processes, renewable options can compete with conventional options better using decisionmaking criteria other than revenue requirements. For example, some states require a societal test in IRP that requires utilities to look at the total cost of providing the electricity service, including environmental costs. To the extent that renewable options result in less harmful environmental emissions than conventional generating alternatives, their chances of adoption are improved using the societal test.

3. GENERATING ALTERNATIVES

3.1. OVERVIEW

In Tables 3.1 through 3.3, we summarize the financial and technology assumptions used to characterize the seven renewable and four conventional technologies. The primary sources of information for the data in these tables were a recent study of renewable technologies commissioned by the National Association of Regulatory Utility Commissioners (Hamrin and Rader, 1993), the *Assumptions for the Annual Energy Outlook 1993* (Energy Information Administration, 1993) and the Electric Power Research Institute's *Technical Assessment Guide* on electricity supply options (EPRI, 1989). Other sources cross-checked for consistency are listed in Table 3.1. The data were also checked for consistency with the assumptions underlying the National Energy Strategy (DOE, 1991/1992).

Two biomass technologies are considered because of provisions of the Energy Policy Act of 1992. Under that legislation, closed-loop biomass systems, in which tree plantations are dedicated to produce feedstock for boilers, are eligible for a $0.015/kWh production incentive if certain conditions are met. Waste-wood biomass systems are not eligible for the credit. Other types of technologies are generally representative of typical power system construction. For most technologies, the region is the Midwest. However, for some renewable technologies such as solar and geothermal, the western part of the United States is applicable. Renewable and conventional technologies are described in greater detail in Sections 3.2 and 3.3, respectively.

The capacities included for each of the technologies are representative of what would currently be constructed, consistent with information available on characteristics of the technology. For renewable technologies, capacities were generally taken from Hamrin and Rader (1993) consistent with the corresponding construction periods provided by EPRI (1989). For conventional technologies, capacities were also based on EPRI (1989) assumptions.

The assumed usage or capacity factors for renewable alternatives are based on data provided by Hamrin and Rader (1993), cross-referenced with the sources listed in Table 3.1. Therefore, given the data in Table 3.1, the only base-load renewable alternatives are biomass and geothermal plants with capacity factors of 70 percent or greater. The hydro alternative chosen for consideration here with a 45 percent capacity factor performs an intermediate duty in the load order. The capacity factors chosen for the conventional alternatives reflect their assumed load duties and are consistent with their relative capital and operating costs. For example, the combustion turbine option has a capacity factor of 10 percent and is used for peaking purposes, consistent with its relatively low capital cost. The combined cycle unit with a 30-percent capacity factor is an intermediate unit, while the coal and nuclear units are used for base-load purposes. The capacity factors for conventional alternatives are generally the ones used for planning purposes (EIA, 1993a; DOE, 1991/1992; and EPRI, 1989).

The total amount of time to construct each of the generating alternatives was taken from EPRI (1989). The total amount consists of a 'preconstruction, licensing,

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Table 3.1
Cost and Engineering Assumptions
Renewable and Conventional Generating Alternatives

Generating Type	Plant: Heat Rate (Btu/kWh)	Plant: Capacity (MW)	Plant: Usage[b] (%)	Plant: Construct[c] (Years)	Plant: Cost[d] ($/kW)	Fuel: Type	Fuel: Cost[e] ($/MWh)	O&M Costs[a]: Variable ($/MWh)	O&M Costs[a]: Fixed ($/kW)
Renewable									
Biomass-Plantation	13,648	50	70	4	1,570	Wood	37.53	9.00	[f]
Biomass-Waste	13,648	50	70	4	1,570	Wood	27.30	9.00	[f]
Geothermal	NA	60	81	4	2,400	NA	NA	10.00	150.00
Hydro	NA	100	45	6	1,067	NA	NA	2.00	6.40
Solar-Photovoltaic	NA	5	22	2	7,200	NA	NA	5.00	[f]
Solar-Thermal	NA	80	20	2	2,885	NA	NA	22.60	[f]
Wind	NA	50	30	2	1,070	NA	NA	10.00	[f]
Conventional									
Coal	10,060	300	65	6	1,512	Coal	14.60	7.00	30.30
Combined Cycle	8,140	120	30	4	590	Gas	19.40	2.20	8.40
Combustion Turbine	13,100	80	10	2	342	Gas	31.20	5.00	0.50
Nuclear	10,530	1,300	70	7	1,548	Uran	4.80	15.00	65.00

SOURCES: Energy Information Administration (1993); Hamrin and Rader (1993); Electric Power Research Institute (1992); Palmerini (1993); National Renewable Energy Laboratory (1990); DeLaquil *et al.* (1993); American Solar Energy Society (1992); and Department of Energy (1991/1992).

NA - Not Applicable.

Table 3.1 (Cont.)
Footnotes

[a]Excluding fuel costs.

[b]Capacity factor--i.e., the portion of the annual maximum number of hours (i.e., 8,760) that the plant is used. The assumed capacity factors are the ones used for the National Energy Strategy (DOE, 1991/1992).

[c]The number of years that it takes to construct the plant. The portion of total expenditures for each year is presented in Table 2. Data for coal, combined cycle, combustion turbine, and hydro generating plant types is that used for the Annual Energy Outlook, 1993 (EIA, 1993). Data for other generating types were obtained from multiple sources, including phone conversations with industry experts.

[d]Overnight construction costs. Data were obtained from multiple sources including EIA (1993), Hamrin and Rader (1993), and ASES.

[e]The cost of fuel in 1991. The assumed growth in fuel prices is presented in Table 3.3 and was obtained from the Annual Energy Outlook, 1993 (EIA, 1993).

[f]Included in the cost of the plant.

Table 3.2
Construction Expenditures
Renewable and Conventional Generating Alternatives

	Renewable Generating Alternatives						Conventional Generating Alternatives			
	Biomass[a]	Geothml	Hydro	Solar Therm	Solar PV	Wind	Coal Steam	Comb. Cycle	Comb. Turbine	Nuclear
Capacity (MW)	50	60	100	80	5	50	300	120	80	1,300
Construction Cost (1991 $Million)[b]	78.5	144.0	106.7	230.8	36.0	53.5	453.6	70.8	27.4	2,012.4
Construction Expenditures (%) (Years before coming on line)										
1	38	38	20	75	75	75	20	38	75	8
2	37	37	25	25	25	25	25	37	25	15
3	13	13	30				30	13		30
4	12	12	13				13	12		30
5			9				9			15
6			3				3			1
7										1
Total	100	100	100	100	100	100	100	100	100	100

SOURCES: Table 1, Electric Power Research Institute (1989), and Energy Information Administration (1993).

[a]The amounts are the same for plants that use both dedicated plantations and waste wood.

[b]Overnight costs.

Table 3.3
Assumed Growth in Fuel Prices
1993-2022

Period	Coal	Natural Gas	Nuclear Fuel	Biomass Waste	Biomass Plantatic
Fuel Price Amounts: ($ 1991 per MMBtu)					
1991	1.45	2.38	1.41	2.00	2.7
Growth in Fuel Prices: (Average annual % growth rates)					
1992-2021	1.3	3.2	0.0	1.0[a]	0.

SOURCE: Calculated from Energy Information Administration (1993).

[a]Assumed to grow at 1.0% per year for the first 10 years.

and design' period and an 'idealized' plant construction time. For the renewabl technologies and coal, combined-cycle, and combustion-turbine alternatives, the numbe of years in each of these phases were evenly divided. For the nuclear alternative, th idealized plant construction time was five years. The time stream of expenditures i percentage terms for those construction periods are provided in Table 3.2. Wher possible, an attempt was made to make the time streams consistent with those used b EIA in producing the *Annual Energy Outlock* (EIA, 1993). However, constructio expenditures are site- and region-specific. To show that our conclusions are invariant t assumptions about the time stream of construction expenditures, sensitivity analyses wer performed for some of the technologies. The results of these analyses are presented i Section 5.4.

The capital and operating costs in 1991 dollars for renewable alternatives wer generally taken from Hamrin and Rader (1993). The amounts were cross-referenced fo consistency with the other sources listed in Table 3.1. The current capital and operatin costs for conventional alternatives are the same as those used by EIA in the *Annua Energy Outlook* (EIA, 1993). Fossil and nuclear fuel costs and their projected growth ove the next 30 years (Table 3.3) are based on forecasts in the *Annual Energy Outlook* (EIA 1993). Plantation and waste-wood fuel costs are based on Hamrin and Rader (1993) cross-referenced with EPRI (1992).

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3.2. RENEWABLE ALTERNATIVES

This section lists key variables and qualifying assumptions for each of the renewable technologies. There is no single source of information that provides point estimates for all of the variables required for this study. However, a recent study completed by Hamrin and Rader (1993) is relatively comprehensive and was chosen as the source for most of the plant and cost level data. Where Hamrin and Rader provide interval estimates for key variables, studies by the American Solar Energy Society (1992), Johansson et al. (1993), DOE (1992), and NREL (1990) are used to reduce the Hamrin and Rader range to a point estimate and/or to provide a verification. As with all studies that provide information on a wide range of technologies, the basic information are abstracted from secondary literature sources and existing studies. Although there may be slight inconsistencies among underlying assumptions given the differing sources of information, these inconsistencies are considered minor relative to the uncertainties inherent in the estimates of capital, fuel, and operating costs. For all technologies listed below, cost data are reported in constant 1991 dollars.

3.2.1. Biomass

The data are for a conventional steam-turbine (spreader-stoker) operating at a net efficiency of about 25%. Plant, fuel, and operating data are derived from Hamrin and Rader (1993). Their estimate of the installed capital cost for the plant is higher than an estimate provided by USDOE (1992). The USDOE estimate ($1366/kW) is about $200/kW less. However, Hamrin and Rader report lower non-fuel operating costs ($0.009/kWh versus $0.0135/kWh). Both of these sources are consistent with the actual installed costs for a similar sized facility using conventional conversion technology. Actual capital costs for the 57 MW McNeil plant (Burlington, VT) were about $80 million or $1410/kW with annual operating and fuel costs of $19.6 million (EPRI, 1992). All report similar capacity factors and fuel costs of $2.00/MMBtu.

3.2.2. Geothermal

The geothermal plant is assumed to use a hydrothermal system (geopressured, hot dry rock, and magma systems, which may offer more promise, are not technologically mature). The costs for hydrothermal systems vary widely and are a function of the resource (dominated by water or steam), the amount of drilling and depth, the productivity per well, the type of gathering system required, and the required environmental controls (reinjection of fluids). Palmerini (1993) reports electricity costs ranging from a low of about $0.03/kWh to over $0.10/kWh (Palmerini, 1993). Hamrin and Rader (1993) cite capital costs from $2400 to $3100/kW. The Interlaboratory White Paper reports capital costs at $1800/kW in 1989 dollars (NREL, 1990). Using the mean of data (well depth, well productivity, etc.) contained in Palmerini implies costs toward the lower end of the $2400 to $3100/kW range. Capital costs were therefore assumed to be at the lower end of the cost interval provided by Hamrin and Rader–$2400/kW, including all net costs of drilling. All other data are taken directly from Hamrin and Rader.

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3.2.3. Hydroelectric

The hydro technology is assumed to be run-of-the-river utilizing off-the-shelf equipment. The costs of hydro projects are highly site dependent and will vary with topography (e.g., civil works), resource conditions (head and flow), distance to nearest transmission line, and the extent of environmental mitigation (e.g., fish passage facilities) measures that may be required. There are no fuel costs with the operation of a hydro facility. Non-fuel O&M costs tend to be low. However, these costs can increase if the facility is required to provide minimum fish flows that result in lost generation, to maintain some threshold dissolved oxygen level, and to operate fish passage facilities. The cost and plant information are derived from Hamrin and Rader. Hamrin and Rader apparently derived their data from the Interlaboratory White Paper, which uses information from a 1986 DOE/EIA report. Hamrin and Rader estimate was inflated to 1991 dollars.

3.2.4. Solar Thermal

The solar thermal application is based on parabolic trough technology. (Solar thermal systems relying on central receivers and parabolic dishes have not been commercialized). The only commercial solar thermal system in use is manufactured by Luz. This system uses natural gas as a backup system. The natural gas backup allows electricity to be sold as firm power during peak load periods. Hamrin and Rader report costs of $3500/kW with the natural gas backup. Capital costs without the natural gas backup are reported by ASES at $2885/kW with O&M costs of about $0.022 to $0.03/kWh. The ASES data are also consistent with those found in DeLaquil et al. (1993) --$2800-$3500/kW capital and $0.018-$0.025/kWh. In this application, the ASES estimate was used.

3.2.5. Solar Photovoltaic

Photovoltaic systems are generally cost effective sources of power for remote and stand-alone applications as well as for a variety of consumer products. Capital costs are relatively high. Hamrin and Rader provide a total installed capital cost range of $6200 to $9000/kW. This estimate includes all balance-of-system components. A point estimate is provided by the ASES at $7200/kW. Both sources report O&M costs at about $0.005/kWh.

3.2.6. Wind

Plant and cost data for a utility-scale wind farm is derived in part from ASES (1992) and Hamrin and Rader (1993). The wind farm is assumed to consist of 250 turbines with each having a rated power output of 200 kW. The installed capital costs for a wind farm are estimated to range between $1000 and $1200/kW (Hamrin and Rader). ASES estimates total capital costs at $1070/kW. O&M costs are placed at from $0.01 to $0.015/kWh by Hamrin and Rader and slightly less than $0.01/kWh by ASES. Capacity factors for wind systems range between 25% and 30%.

3.3. CONVENTIONAL ALTERNATIVES

In contrast to the renewable alternatives (with the exception of hydro), many more conventional plants exist with years of operating experience and, therefore, much more information and data on their operating characteristics. For the study, we tried to select 'representative' plant types. For the coal alternative, for example, we selected a plant that would likely operate in the midwestern portion of the country.

3.3.1. Coal

The data in Table 3.1 represent a 300-MW, coal-fired steam unit with flue gas desulfurization (FGD). The unit is assumed to burn Illinois bituminous, high-sulfur coal and is located in the East/West Central portion of the country. The major components of the plant include coal-handling equipment, steam-generator island, turbine-generator island, FGD system, bottom and fly ash handling system, and the stack. The FGD system achieves 90% SO_2 removal.

3.3.2. Combined Cycle

The combined cycle plant is a conventional unit burning natural gas and is used in the East/West Central region of the country. Combustion turbine generators account for two-thirds of the power and one-third comes from a steam turbine generator. A heat recovery system accounting for the steam generation improves the efficiency of the system. NO_X emissions are controlled by injecting water or steam into the combustor. More stringent NO_X emission standards may require selective catalytic reduction.

3.3.3. Combustion Turbine

The combustion turbine is a conventional system that would be constructed in the East/West Central portion of the country. The unit consists of an air compressor, a combustor, and an expansion turbine. NO_X emissions are controlled by injecting water or steam into the combustor. Because the power output of a combustion turbine is very sensitive to the ambient temperature, it is assumed that the ambient temperature for the data presented in Table 3.1 is 59°.

3.3.4. Nuclear

The data for the nuclear unit are based on current experience for building large, commercial nuclear power plants of U.S. design world-wide. We are basing our analysis on two U.S. advanced boiling water reactor units that are under construction for the Tokyo Electric Power Company at the Kashiwazaki-Kariwa site, and the construction time from first concrete pour to fuel load is expected to be less than four years. Additionally, four U.S. pressurized water reactor units are under construction in Korea and also will be completed in less than four years. For a U.S. application, we assume a five-year construction period and, with passage of EPACT, a two-year licensing period for a total construction and licensing period of seven years (Table 3.2). Nuclear plants in operation in the U.S. are experiencing total O&M (fixed and variable) costs as low as 8 mills/kWh, but averaging 15 mills/kWh; and capacity factors exceeding 90 percent, but averaging 70 percent. Although it is expected that Advanced Light Water Reactors, to be completed in the next decade, will achieve a lower average O&M cost and a higher average capacity factor, this study assumes actual experiences to date.

4. TAXATION, RATEMAKING, AND DEFINITION OF SCENARIOS

In this section, we define the scenarios that will be simulated using the financial regulatory model described in Appendix A. The scenarios are placed in the context of current taxation and ratemaking policies. That is, each variant from the reference scenario is chosen to reflect departures from existing federal, state, and local tax laws and the application of ratemaking principles in individual states.

The reference scenario is defined in Section 4.1. For IOUs and NUGs, tax scenarios deviating from the reference scenario are defined in Section 4.2. For IOUs exclusively, ratemaking scenarios deviating from the reference scenario are defined in Section 4.3.

4.1. REFERENCE SCENARIO

In the reference scenario, we define financial conditions for IOUs and NUGs that come as close as possible to representing the types of conditions that a typical IOU or NUG would confront in the real world, recognizing differences in ratemaking and tax types across the 50 states. We assume that the typical IOU or NUG is subject to the following:

- 3% local property taxes,
- sales and payroll taxes on construction and operating expenses
- 6% state income taxes,
- 35% federal income tax,
- differences between tax and book depreciation for federal and state income taxes, depending on the type of ownership and the type of technology (defined in Table 4.3),
- federal production tax credits for integrated biomass systems and wind technologies, and
- federal investment tax credits for solar and geothermal technologies.

In addition, for IOUs we assume that (1) no CWIP is allowed in the rate base for ratemaking purposes, (2) all differences between tax provisions for tax and book purposes are 'normalized' in determining rates, and (3) all assumed changes in the real cost of fuels are passed on to the ratepayer in the year in which they are experienced by the utility.

In addition to the tax and ratemaking factors considered above, financial parameters applicable to the utility or NUG are defined to execute the financial regulatory model described in Appendix A. In Table 4.1, we show these parameters for IOUs, along with representative values. In most cases, the title of the input parameter is self-explanatory. Debt ratio is the percentage of assets financed through debt. This study used constant dollars for its analysis and no inflation. Consequently, average allowed returns on debt and equity were reduced by 4% points from real world values averaging

9% and 11%.[1] Construction and O&M cost escalation rates were kept at 0%. Fuel escalation rates varied, depending on the type of fuel. Table 3.3 shows the rates used for fuel costs.

Table 4.1
Financial Parameters for Investor-Owned Utilities

Parameter	Value	Parameter	Value
Work Capital % of O&M	12.5%	CWIP allowed in Rates	*
Debt Ratio	50%	Normalized Tax	Yes
Labor Tax Rate	10%	Interest Rate	5.0%
Energy Tax Rate	5.0%	Allowed Return on Equity	7.0%
Material Tax Rate	5.0%	Fuel Recover Lag, years	*
Land Tax Rate	5.3%	Fed. Income Tax Rate	35%
Construction Escalation rate	*	State Income Tax Rate	6%
O&M Escalation rate	*	Property Tax Rate	3.00%
Fuel Escalation rate	*	Property Tax Method	Net Book

*Values depend on the specific circumstances of the scenarios that are simulated.

A working capital account was established equal to 12.5% of the next year's operations and maintenance cost. This caused the utility to issue additional equity and debt the year before operation and to recover this money in the last year of operation.

Similar financial information for NUGs is presented in Table 4.2. Most financial data is the same as for the IOU reference scenario. Parameters that are different are the sales price, the debt ratio, and flags to use the alternative minimum tax and/or the carry forward of tax losses. The debt ratio was set at 80% for the NUG scenarios. This reflects the increased use of debt by non-utility generators in the construction of their plants.

The sales price is equal to the levelized cost to customers from the reference IOU scenario for each technology. This means that for each technology, as far as customers

[1] Relaxing the constant-dollar assumption does not affect the conclusions of the study. Simulation results using current dollars are reported in Section 5.4.

Table 4.2
Financial Parameters for Non-Utility Generators

Parameter	Value	Parameter	Value
NUG Sales Price, ¢/kWh	[a]	Alternative Minimum Tax	No
Debt Ratio	80%	Carry Forward Losses	No
Labor Tax Rate	10%	Interest Rate	5.0%
Energy Tax Rate	5.0%	Work Capital % of O&M	12.5%
Material Tax Rate	5.0%	Fed. Income Tax Rate	35%
Land Tax Rate	5.3%	State Income Tax Rate	6%
Construction Escalation rate	[a]	Property Tax Rate	3%
O&M Escalation rate	[a]	Property Tax Method	Net Book
Fuel Escalation rate	[a]		

[a]Values depend on the specific circumstances of the scenarios that are simulated.

are concerned, the cost of either the IOU scenario or NUG scenario are the same. It also makes the utilities relatively indifferent to the ownership. The net effect is to remove the NUG price as a major factor in this analysis.

4.2. ALTERNATIVE TAX SCENARIOS FOR IOUs AND NUGs

After the reference scenarios were established, a number of variations on the different tax rates and tax methods were performed. These were done to identify the relative impact of each parameter on the key criteria. By identifying tax parameters that had a significantly different effect on renewables versus conventional technologies, we could identify those which may create a disincentive for one or the other.

Synergies existed among some of the input parameters. Modifying one of the variables amplified the effect of others. To study this in more detail, we ran combined scenarios and measured their results against the scenarios with only one of the parameters altered.

4.2.1. Effect of All Taxes

The first variation to the reference case was to run each technology with no taxes

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of any kind. This also meant that tax credits were set at zero.

4.2.2. Property Tax Effects

We used a property tax rate of 3% of the net book value of the plant and equipment, including land, in the reference scenarios. We based this on an analysis of the typical rate charged by states and localities, when adjusted for differences in assessment value used as a percentage of full assessed value. Net book value (gross plant and equipment less depreciation) was used as representative of the market value assessment that would be placed on a plant.

In reality, property taxes vary across the country by wide amounts, depending largely on local tax needs. According to the report from the U. S. Advisory Commission on Intergovernmental Relations, tax rates can vary from less than 1% to over 10% in different localities. Generating plants are usually located in rural areas, which tend to have lower property tax rates. However, these plants are often the major source of revenues for local governmental needs such as schools and fire protection.

To understand the effect of different methods for calculating the property tax base we used two other methods, gross book value and the net present value of the future cash flow stream. Also, we studied the effect of charging property tax on the added plant and equipment but not on the original land value.

4.2.3. Taxes on Construction and Operating Inputs

The costs that go into building and operating a generating plant often have taxes placed on them. We split capital costs into four categories: labor, energy, material, and land. Labor and material each were assigned between 40% and 45% of the capital cost. Energy was assigned 10% and land 5%. Wind was given a land value of 10% to reflect the higher land requirement for this technology. We split the O&M costs between labor and material.

Representative tax rates on the input labor, energy, material, and land were established as shown in Table 4.1. Labor taxes represent such factors as social security and unemployment taxes. The values used are to represent only the company's contribution. Energy, material, and land taxes are based on a 5% sales tax with an additional 0.3% deed transfer tax for land. These are based on approximate average values for the states and localities; actual amounts vary widely from 0% to over 9%. Also, some states exclude businesses from sales tax. For this study, fuel tax rates are assumed to be the same as for other materials going into the plant, but actual taxes on fuel may be based on different parameters.

4.2.4. State Income Tax Effects

We set the state income tax to zero to understand its effect on the technologies. Our reference case used an input rate of 6%. Because state taxes are deductible from federal taxes, the net state tax rate in the model for the reference case was about 4%. As with property taxes, the actual rates varied across the states from 0% to more than 10%.

4.2.5. Federal Income Tax Effects

To study the effect of income taxes, we set the federal tax rates at zero. The reference case uses a federal tax rate of 35%. In addition, federal tax credits were set to zero as well. This means that the dedicated biomass plant and wind plant did not have the production tax credit and the geothermal and solar technologies did not have the investment tax credit. By zeroing both taxes and credits, we could understand the combined effect of the major federal tax policies. We ran a separate scenario eliminating the credits only (see Section 4.2.7)

4.2.6. Effects of Federal Tax Depreciation Lives

Federal tax depreciation law is affected by three asset depreciation systems defined in three different pieces of legislation. The Modified Accelerated Cost Recovery System (MACRS), introduced by the Tax Reform Act of 1986, is mandatory for depreciating most tangible property placed in service after 1986. MACRS substantially changes the Accelerated Cost Recovery System (ACRS) for tangible property placed in service after 1980 and before 1987. ACRS was created as part of the Economic Recovery Tax Act of 1981. Pre-1981 assets are depreciated under provisions of the Revenue Act of 1971 which created the Asset Depreciation Range (ADR) depreciation system. Today, both MACRS and ACRS are related to the ADR system in that property is generally classified by reference to class lives.

Under MACRS, the cost of depreciable property is recoverable over 3, 5, 7, 10, 15, 20, 27.5, or 31.5 years, depending on the type of property through use of statutory recovery methods. Those statutory recovery methods relate a 'class life' as defined in the ADR depreciation system to a recovery period under MACRS. These relationships were defined in two revenue procedures subsequent to enactment of the Tax Reform Act of 1986. In Table 4.3, the recovery periods (i.e., the tax lives) for conventional technologies and hydroelectric are based on the table of MACRS Tax Lives.

Classes of depreciable property are defined by Code Sections 1245 and 1250 property and the class life as of January 1, 1986. The class life of an asset affects its recovery period, the method of depreciation used, and the applicable convention. Under MACRS, five-year property generally includes property with a class life of more than four years and less than ten years. Specifically added to this class are

- geothermal, solar, and wind energy properties; and
- certain biomass properties that are small power production facilities.[2]

The effects of this section of the code are also contained in Table 4.3 for biomass systems operated by non-utility generators (i.e., qualifying facilities in terms of the code),

[2] IRS Code Sec 168(e)(3).

Table 4.3
Book and Tax Depreciation Lives
Renewable and Conventional Generating Alternatives

Generating Alternative	Investor-Owned Utilities[a]			Non-Utility Generators		
	Book	Tax	Internal Revenue Source	Book	Tax	Internal Revenue Source
Renewable						
Biomass-Plantation	30	20	Rev. Proc. 88-22, 1988-1 CB 785	30	5[b]	IRS Code Sec. 168(e)(3)
Biomass-Waste	30	20	Rev. Proc. 88-22, 1988-1 CB 785	30	5[b]	IRS Code Sec. 168(e)(3)
Geothermal	30	5	IRS Code Sec. 168(e)(3)	30	5	IRS Code Sec. 168(e)(3)
Hydro	50	20	Rev. Proc. 88-22, 1988-1 CB 785	50	20	Rev. Proc. 88-22, 1988-1 CB 785
Solar-Photovoltaic	30	5	IRS Code Sec. 168(e)(3)	30	5	IRS Code Sec. 168(e)(3)
Solar-Thermal	30	5	IRS Code Sec. 168(e)(3)	30	5	IRS Code Sec. 168(e)(3)
Wind	30	5	IRS Code Sec. 168(e)(3)	30	5	IRS Code Sec. 168(e)(3)
Conventional						
Coal	30	20	Rev. Proc. 88-22, 1988-1 CB 785	30	20	Rev. Proc. 88-22, 1988-1 CB 785
Combined Cycle	30	20	Rev. Proc. 88-22, 1988-1 CB 785	30	20	Rev. Proc. 88-22, 1988-1 CB 785
Combustion Turbine	30	15	Rev. Proc. 88-22, 1988-1 CB 785	30	15	Rev. Proc. 88-22, 1988-1 CB 785
Nuclear	30	15	Rev. Proc. 88-22, 1988-1 CB 785	30	15	Rev. Proc. 88-22, 1988-1 CB 785

[a]For all renewable and conventional technologies, assumes that investor-owned electric utilities 'normalize' book to tax differences in accelerated depreciation for ratemaking purposes.

[b]Only available for 'qualifying facilities' under the Federal Power Act, one type of non-utility generator.

and geothermal, solar, and wind plants operated by investor-owned utilities and nonutilit generators.

All of these depreciation provisions under MACRS listed in Table 4.3--anc including the ones related to renewable generating technologies--do not pertain to 'publi utility property,' *unless a normalization method of accounting is used.*[3]

'Public utility property' that does not qualify under MACRS is depreciated unde Code Sec. 167(a) using the same depreciation method and useful life as is used tc compute the ratemaking depreciation allowance for the asset.

In the reference scenario, normalization is used for tax accounting. Therefore, al of the favorable tax lives provided by MACRS for both conventional and renewable generating technologies as shown in Table 4.3 are available for both IOUs and NUGs. However, as discussed in Section 4.3.2, a ratemaking scenario deviating from the normalization case is simulated.

Under MACRS, the cost of depreciable property is recovered using (1) the applicable depreciation method, (2) the applicable recovery period, and (3) the applicable convention (Code Section 168(a)). However, instead of the applicable depreciation method, taxpayers may elect to claim straight-line MACRS deductions over the regular recovery period. Additionally,

- the cost of property recovered over 3, 5, 7, and 10 years is recovered using the 200% declining-balance method, the half-year convention, with a switch to the straight-line method in order to maximize the deduction (Code Sec. 168(b)(1))).

- the cost of property recovered over 15 and 20 years is recovered by the 150% declining balance method, using the half-year convention, with a switch to the straight-line method at a time to maximize the deduction (Code Sec. 168(b)(2)).

In our depreciation accounting, we use the 200% and 150% variants as specified in the legislation.

4.2.7. Effects of Federal Tax Credits

Provisions of EPACT allow tax credits for the production of electricity using closed-loop biomass and wind energy sources (i.e., a production tax credit) and extends the tax credit for investment in solar and geothermal electric generating stations. These credits are available to any taxpayer (i.e., IOU or NUG) that meets the performance and quality standards of the legislation.

The reference cases included the tax credits available to IOUs and NUGs. The

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[3]IRS Code Sec. 168(i)(10).

credits were not allowed in the scenario excluding all taxes (Section 4.2.1 above), the scenario excluding federal income taxes (Section 4.2.5) and the scenario excluding tax credits.

According to section 1914 of EPACT, a production tax credit of 1.5 ¢/kWh is available for wind and closed-loop biomass, with some limitations. The key factor is that the tax is phased-in as the price of electricity generated falls below 11¢/kWh and reaches the full 1.5 ¢/kWh when the price is at or below 8¢/kWh. Also, the credit is available only during the first 10 years of a plant's operation.

Section 1916 of EPACT permanently extends the investment credit (i.e., the energy investment credit) for solar and geothermal property. The credit equals 10 percent of the value of solar and geothermal facilities placed in service. Up until recently, both NUGs and IOUs could take advantage of the ITC. IOUs had to normalize the benefits of the credit over the useful life of the asset to take advantage of the ITC. Recent changes in tax law, however, only allow NUGs to take advantage of the ITC for solar and geothermal property. IOUs are excluded from the benefit.

4.2.8. Effects of the Alternative Minimum Tax (AMT)

The AMT was created to ensure that at least a minimum amount of income tax is paid by corporate and high-income non-corporate taxpayers who derive large tax savings from certain provisions of the Code, including favorable tax depreciation provisions under MACRS. All taxpayers whether corporate or non-corporate must make a depreciation adjustment. For property placed in service after 1986, the alternative depreciation system must be used. MACRS deductions are reduced for certain property by requiring that an 'alternative MACRS' method based on generally longer recovery periods be used (Code Sec. 168(g)). In computing depreciation for AMT purposes, the 'alternative MACRS' must be used with certain modifications.

After taxable income is adjusted by the alternative depreciation amounts, a lower income tax rate of 20% is applied. If income taxes are higher using the adjusted income and tax rate than taxes under the regular rate using standard MACRS rules, then the corporation must pay the higher tax.

The reference scenarios for the IOUs and NUGs did not have the AMT. It was assumed that the corporations would have sufficient depreciation from older facilities to make the net tax higher under the input 35% rate. A sensitivity was run for NUGs in which the alternative minimum tax did apply. The model calculates taxes under both the regular MACRS rules and 35% rate, and using the alternate depreciation schedule and a 20% rate. The higher of the two taxes in each year is then what was owed to the federal government.

In the reference scenarios tax losses occurred in some years, resulting in a negative income tax. Supposedly, the government would then pay the company. In actuality, we assume that the corporation (IOU or NUG) would have sufficient positive income from other investments to offset these losses. The "negative taxes" would actually be a reduction in the total taxes the corporation would pay that year.

If a corporation does not have offsetting positive taxes, it would either apply these losses to profits made in earlier years (i.e., carry back the losses), or it would carry forward the losses to apply them against profits in a future year. There are limits on how far back or forward a corporation may carry tax losses. We did not model carry-back of losses, but did model the option to carry losses forward a maximum of 15 years. This is because tax losses occur mainly in the early years of operation, so that there are not profits in earlier years to which carry-back can apply.

We only applied this carry-forward of losses scenario to NUGs because they are more likely to be small companies to which the requirement applies.

4.3. ALTERNATIVE RATEMAKING SCENARIOS FOR IOUs

4.3.1. Treatment of Construction Work in Progress

When state regulatory commissions set rates for utilities in their jurisdiction, they use a set of ratemaking procedures that determine what costs are included for recovery. Appendix A describes the methodology used within this study to simulate the regulatory process. It includes establishing a rate base for which the utility may earn a return on its investment, fuel costs, O&M costs, taxes, and depreciation. The sum of these provides the amount of required revenues for the modeled project. We assumed that the utility would incorporate this amount with the required revenue from its other operations (not modeled) in determining its overall electricity prices.

If a utility receives no revenue from CWIP in the rate base, it includes an accounting revenue called Allowance for Funds Used During Construction (AFUDC) on its books. This is the amount of return the utility would have earned on the plant each year and is based on the debt and equity rates and cost of capital. This amount gets capitalized on the books as an asset and compounds over time. When the plant starts producing electricity AFUDC is included in the rate base of the plant. It then is depreciated like the other capital costs and recovered in the revenues.

4.3.2. Normalization vs. Flow-Through Tax Accounting

If there were no differences between provisions of the tax law and accounting for ratemaking, the question of normalization would not arise. Because of the MACRS depreciation system, however, timing differences arise between ratemaking accounting and tax accounting. That is, expenses are recorded for tax purposes in one year and for book purposes in another. Over a sufficient number of years, these expenditures have the same nominal effect on both financial and tax accounting.

Regulatory commissions historically have used two methods to deal with these differences in ratemaking. First, the utility defers the tax benefits and amortizes them over the useful life of the asset. Or, a charge is made to current operations ('provision for deferred taxes') and a corresponding credit is made to a deferred liability ('reserve for deferred taxes'). When the timing difference turns around, the reverse entry is made (i.e., income is credited and the reserve charged.) Under the second method, 'flow-through accounting,' no deferred reserve is created. The current tax benefits are not amortized for ratemaking, but impact rates in the current period.

A similar option exists for the investment tax credit (ITC). The ITC allows utilities a dollar-for-dollar credit against their federal income tax liability for a specified percent of the amount of the investment in a qualified plant. From an accounting standpoint, the ITC represents a permanent savings in taxes rather than a deferral. The key ratemaking question is the year in which tax expense should be reduced for ratemaking purposes.

Like depreciation accounting for timing differences, discussed above, there are two methods used to reflect the impact of ITC for ratemaking purposes. The first method requires a deferral of the credit in the year that it is realized. The amount of the credit is then amortized over the useful life of the property. The second method allows the entire credit to affect book income the year in which the asset is placed in service.

4.3.3. Fuel Adjustment Clauses

Regulatory commissions set the level of required revenues based on the expected costs for a future period. Fuel costs are the most volatile of these costs and may be significantly different from what was predicted. Recognizing this, many commissions allow utilities to automatically adjust their rates as fuel costs change without requiring a new rate hearing. This practice protects the utility from the financial risk of absorbing the extra costs if fuel prices increase faster than expected.

In our reference scenario, we capture the effects of a fuel adjustment clause. As an alternative scenario, we modeled a case in which the commission expects that fuel costs would escalate only at the general rate of inflation. Any increase above that would not be recovered until the following year. In a sense, this portrays commissions as less prescient than reality dictates. On the other hand, we use only a single escalation rate for fuel for all years. In the real world, fuel prices would increase at rates both greater and lower than the average value that we used.

Many advocates of renewable technologies argue that passing all fuel price increases on to ratepayers--whether instantaneously or on a lag--represents an incentive for utilities to adopt conventional technologies because fuel costs represent a large portion of the total costs of using conventional technologies. Most renewables do not require fuel and, therefore, are generally more capital-intensive than conventional technologies. Utilities, it is argued, are exposed to more risk from capital-intensive technologies because of the danger that commissions may disallow a portion of capital expenditures in the rate base as a result of prudency reviews.

To see the effects of disallowing a portion of fuel price increases to be passed along to ratepayers, we conducted a sensitivity analysis. The results of that analysis are presented in Section 5.4 along with other sensitivity results.

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5. SIMULATION RESULTS FOR INVESTOR-OWNED UTILITIES

5.1. SUMMARY

In Table 5.1, we compare the results of different tax measures with the reference case. As in Table 1.1, the results in Table 5.1 reflect the ratio of the reference case—which includes a 35% federal tax on income, accelerated tax depreciation, and federal production tax credits—to a scenario that does not include the subject tax, depreciation, or credit. The results in Table 5.1, unlike those in Table 1.1, also include the second decisionmaking criterion for IOUs: the internal rate of return (IRR). For levelized costs, values greater than 1 indicate increases in cost and therefore barriers to adopting the technologies. The reverse is true for values less than 1. Conversely, for IRR, values greater than 1 indicate increases in IRR and are therefore incentives to adopting the technology. The reverse is true for values less than 1.

The value of 1 for the reference case of each technology and decisionmaking criterion reflects the ratio of values of the simulation results for levelized cost and IRR to themselves. For information purposes, we show the breakdown of costs for the reference cases of each technology in Fig. 5.1. The cost components sum to 100%. The negative components below the 0% indicator offset the costs above the 100% line. Because the levelized cost calculation is based on required revenues from the rate base, the capital costs include both depreciation and return on investment. The characterization of technologies in Fig. 5.1 indicates the relative capital intensity of each of the technologies adopted by a "representative" utility without quantifying the levelized costs of those technologies. The figure shows the relatively higher capital intensity of the renewable technologies in comparison with conventional ones. This observation will be important later in interpreting the results of many of the scenarios.

In Table 5.1, in the first scenario we show the effects of all taxes and credits—local, state, and federal—on levelized cost and IRR. The results for the levelized costs of all the technologies are depicted in Fig. 5.2. For conventional technologies, all taxes raise costs by approximately 20%. For renewable technologies, on the other hand, the simulations indicate a more varied response to taxes. While most renewables show effects from taxes similar to or higher than the effects for conventional technologies, the levelized costs of dedicated biomass and wind plants decrease when taxes are imposed. To see why, we analyzed the effects of each tax measure.

The effects of property taxes shown in Table 5.1 indicate the relatively higher capital-intensity of renewable technologies (especially hydro, solar, and wind) compared with conventional ones, with cost increases on the order of 20–30%. This is discussed in more detail in Sect. 5.2.2.

As Table 5.1 shows, input taxes (on labor, fuel, material, and land) increase costs approximately 7%. The effects of the different input taxes are discussed in more detail in Sect. 5.2.3.

Table 5.1
Summary of Tax Effects on Levelized Cost and Internal Rate of Return, Investor-Owned Utilities
(Ratio of Case With Taxes to Case Without)

Generating Type	Effect of Including All Taxes and Credits	Effect of Including Property Taxes	Effect of Including Input Taxes	Effect of Including State Income Taxes	Effect of Including Federal Taxes and Credits
RENEWABLES					
Biomass-Plantation					
Levelized Cost	0.97	1.09	1.07	0.99	0.85
Int. Rate of Return	0.99	1.00	1.00	1.00	0.99
Biomass-Waste					
Levelized Cost	1.19	1.08	1.06	1.01	1.03
Int. Rate of Return	0.99	1.00	1.00	1.00	0.99
Geothermal					
Levelized Cost	1.16	1.11	1.07	1.00	0.98
Int. Rate of Return	0.95	1.00	1.00	0.99	0.96
Hydro					
Levelized Cost	1.40	1.24	1.07	1.01	1.04
Int. Rate of Return	0.98	1.00	1.00	1.00	0.98
Solar-Photovoltaic					
Levelized Cost	1.27	1.27	1.07	0.99	0.95
Int. Rate of Return	0.94	1.00	1.00	0.99	0.95
Solar-Thermal					
Levelized Cost	1.24	1.23	1.07	0.99	0.95
Int. Rate of Return	0.94	1.00	1.00	0.99	0.95
Wind					
Levelized Cost	0.91	1.31	1.10	0.97	0.71
Int. Rate of Return	0.95	1.00	1.00	0.99	0.95
CONVENTIONALS					
Coal					
Levelized Cost	1.22	1.09	1.07	1.01	1.04
Int. Rate of Return	0.99	1.00	1.00	1.00	0.99
Combined Cycle					
Levelized Cost	1.18	1.07	1.06	1.00	1.03
Int. Rate of Return	0.99	1.00	1.00	1.00	0.99
Combustion Turbine					
Levelized Cost	1.18	1.09	1.06	1.00	1.02
Int. Rate of Return	0.98	1.00	1.00	1.00	0.98
Nuclear					
Levelized Cost	1.20	1.09	1.07	1.00	1.03
Int. Rate of Return	0.98	1.00	1.00	1.00	0.98

Note: The tax effects are the ratios of the levelized costs and IRRs of the cases with taxes to the cases without the taxes. Levelized cost ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives. IRR ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

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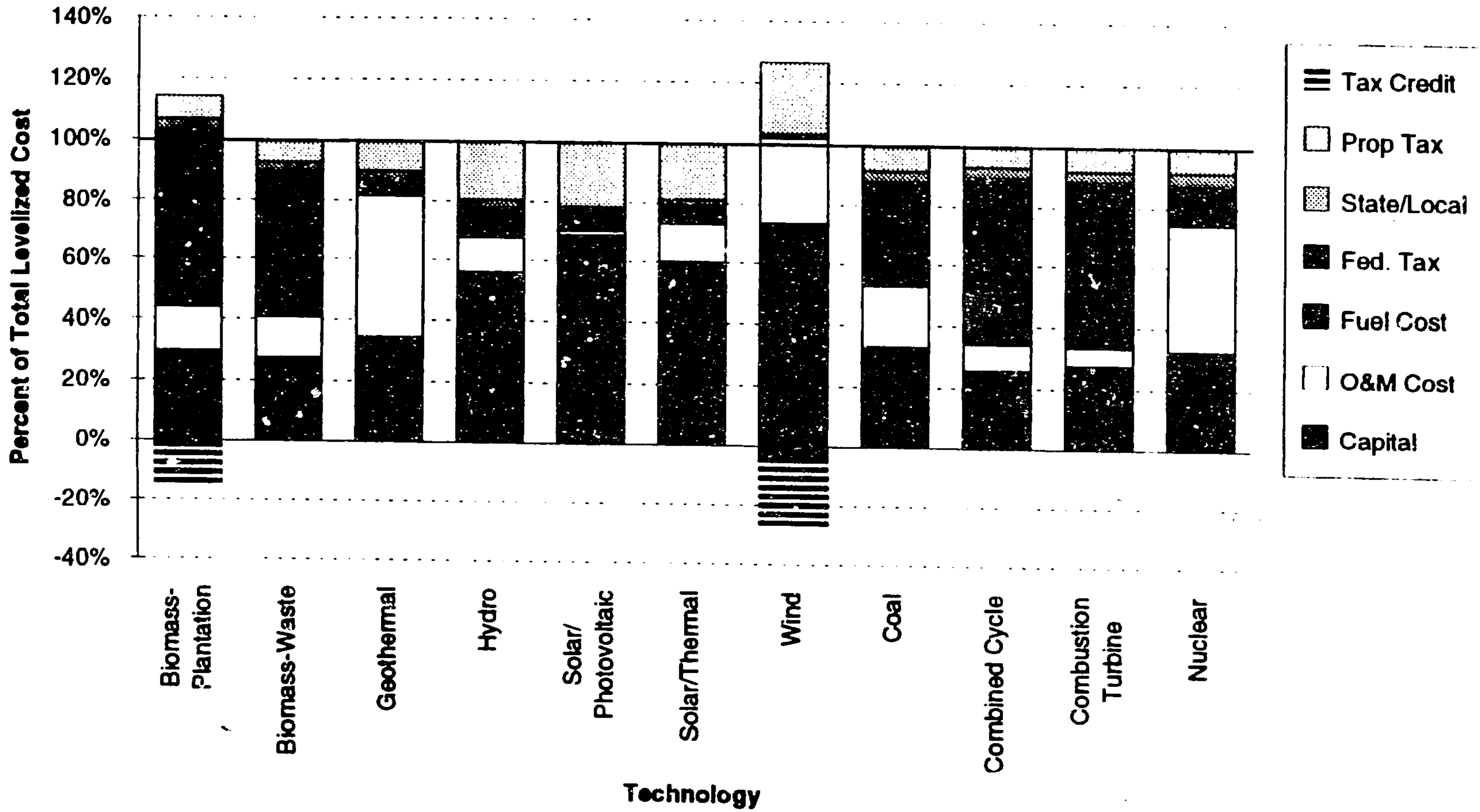
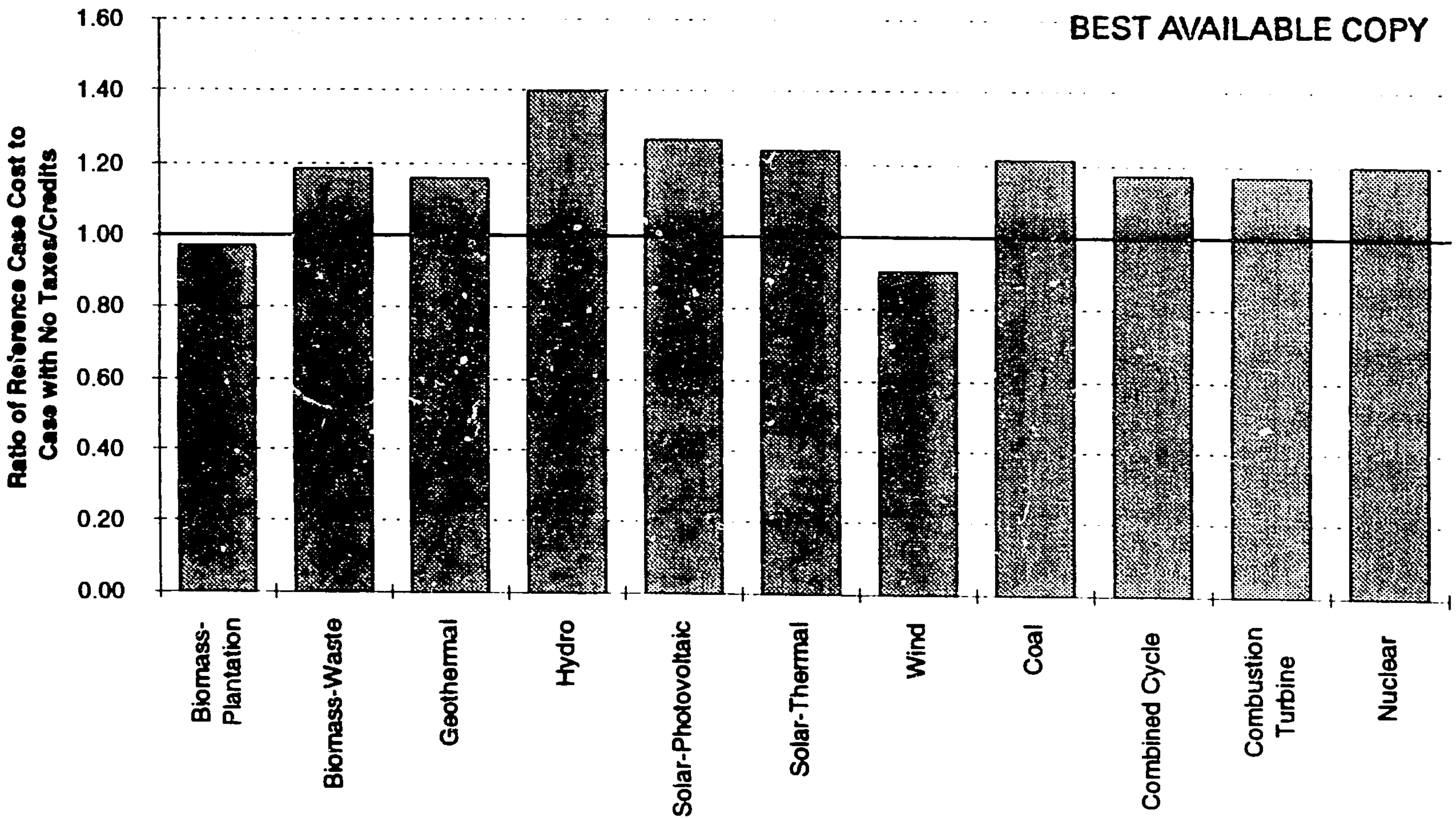
Figure 5.1
Levelized Cost Components for Each Technology, IOU Reference Scenarios



Note: Costs for each technology sum to 100%.

Figure 5.2
Effect of All Taxes and Credits on Levelized Cost, Investor-Owned Utilities



Ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives

Changes in costs due to the 6% state income tax are small, but favorable, for several of the renewable technologies. This is due largely to accelerated depreciation of investment in plant and equipment, which mirrored the tax lives used for federal purposes. These effects are described in more detail in Sect. 5.2.1.

The effects of federal income taxes (including accelerated depreciation) and production tax credits quantified in Table 5.1 are characterized in Fig. 5.3. Technologies which have no tax credits associated with them and which have fairly long tax depreciation lives (i.e., the conventionals, hydro, and waste wood biomass plants) are harmed by federal taxes by approximately 2–4%. Renewables that have short tax depreciation lives and are able to take advantage of production tax credits benefit from federal taxes. These issues are discussed in detail in Sect. 5.2.1.

We also examined the effects of three ratemaking procedures—the amount of CWIP allowed in the rate base, normalization vs flow-through of taxes and credits, and the ability of IOUs to pass fuel price increases automatically to ratepayers—on decisionmaking criteria that IOUs use. We show the results of these scenarios in Table 5.2.

As can be seen by the results in Table 5.2, allowing all of CWIP in the rate base has negligible effects on the criteria considered. The rate base calculation adjusts required revenues to provide an allowed return to the utility each year. Because the model discounts the costs and returns over the life of the facility by the allowed returns, there is essentially no net change in the criteria. This is discussed in Sect. 5.3.1.

In the reference scenario, taxes and credits are normalized. This means that the reduction in taxes due to accelerated depreciation are not passed directly to the ratepayers in the year of their occurrence, but are spread over the life of the facility. Customers pay the deferred credits early, at which point a reserve for payment of deferred taxes is established as a liability on the balance sheet. Later in the plant's life, this reserve is depleted as the deferred taxes are paid.

When taxes flow through to customers, the levelized cost increases. The capital-intensive renewables experience increases in cost of over 10%, while the conventionals experience cost increases of around 2%. There are several reasons for these results. They are discussed in more detail in Sect. 5.3.2.

The results of the automatic fuel adjustment clause as modeled indicate little effect on the decisionmaking criteria. Gas-fueled technologies are the most sensitive because gas prices are assumed to increase faster than the prices of other fuels. The levelized cost for a combustion turbine declines 0.1% without the clause because of delays in passing the higher fuel prices to customers. For example, the IRR declined 0.6% because of the delay in receiving the funds. The major issue with fuel adjustment clauses is not the economic impact on the utility and its customers but the lessening of financial risk to the utility from fuel cost increases. This lowers the riskiness of fuel-intensive technologies more than the capital-intensive technologies.

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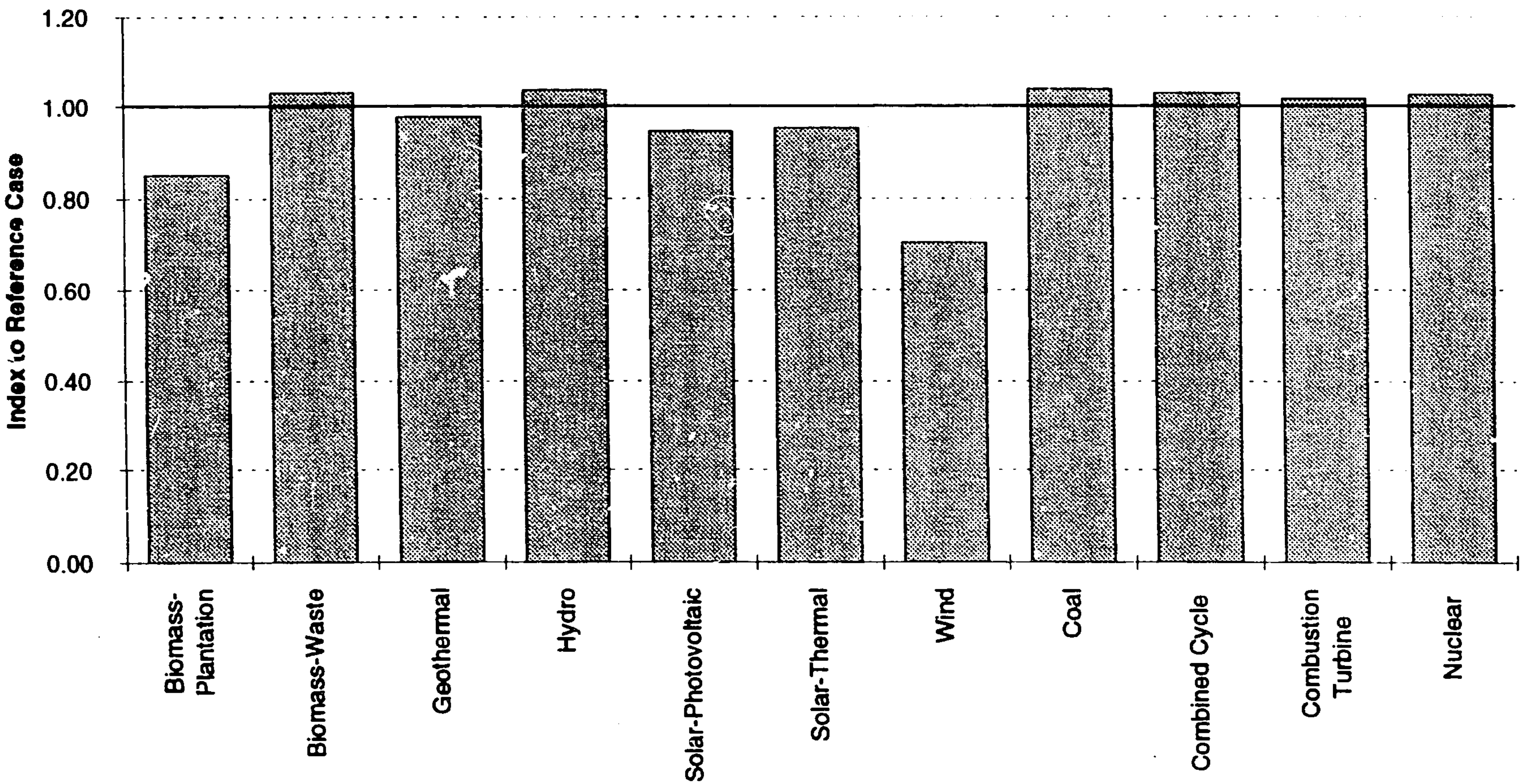
Figure 5.3
Effect of Federal Taxes and Credits on Levelized Cost,
Investor-Owned Utilities



Ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives.

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Table 5.2
Summary of Ratemaking Effects on Levelized Cost and Internal Rate of Return, Investor-Owned Utilities

(Ratio of Case with Ratemaking Procedure to Case Without)

Generating Type	Effect of Not Including CWIP in Rate Base	Effect of Normalizing Taxes in Rate Base	Effect of Automatic Fuel Adjustments
RENEWABLES			
Biomass-Plantation			
Levelized Cost	1.00	0.98	1.00
Int. Rate of Return	1.00	0.99	1.00
Biomass-Waste			
Levelized Cost	1.00	0.98	1.00
Int. Rate of Return	1.00	0.99	1.00
Geothermal			
Levelized Cost	1.00	0.94	1.00
Int. Rate of Return	1.00	0.95	1.00
Hydro			
Levelized Cost	1.00	0.90	1.00
Int. Rate of Return	1.00	0.98	1.00
Solar-Photovoltaic			
Levelized Cost	1.00	0.89	1.00
Int. Rate of Return	1.00	0.94	1.00
Solar-Thermal			
Levelized Cost	1.00	0.90	1.00
Int. Rate of Return	1.00	0.94	1.00
Wind			
Levelized Cost	1.00	0.89	1.00
Int. Rate of Return	1.00	0.95	1.00
CONVENTIONAL			
Coal			
Levelized Cost	1.00	0.98	1.00
Int. Rate of Return	1.00	0.99	1.00
Combined Cycle			
Levelized Cost	1.00	0.98	1.00
Int. Rate of Return	1.00	0.99	1.01
Combustion Turbine			
Levelized Cost	1.00	0.98	1.00
Int. Rate of Return	1.00	0.98	1.01
Nuclear			
Levelized Cost	1.00	0.97	1.00
Int. Rate of Return	1.00	0.98	1.00

Note: The ratemaking effects are the ratio of the levelized costs and IRR of the scenarios with the ratemaking by the cost and IRR without the procedure. Levelized cost ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives. IRR ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

5.2. KEY TAX EFFECTS

Only some of the tax measures have a major impact on the costs of th technologies. Of those studied, aspects of federal income tax policy were the mos significant. Tax depreciation lives and the availability of tax credits were the mos important factors. Apart from federal taxes, local property taxes also affect capital intensive technologies more than those that are not as capital-intensive.

5.2.1. Federal Income Tax Effects

The effect of federal income taxes and credits were surprising. As shown in Fig 5.3, the conventionals and two of the renewables had slight increases (2–4%) in their cos because of taxes. But the remaining renewables showed significant declines. There ar two main reasons for the difference. Four of the renewables used a double-declinin balance, 5-year-tax-depreciation life. In addition, two renewables used the production ta credit. In Table 5.3 we show the results of varying these parameters separately an together.

First, we studied accelerated depreciation by itself by setting the tax depreciatio equal to book depreciation. (The reference tax and book lives are listed in Table 4.3.) Th geothermal, solar, and wind technologies had tax lives of 5 years and consequently use a double-declining-balance depreciation schedule. The rest of the technologies had ta lives of 15 or 20 years. As can be seen in Table 5.3 and Fig. 5.4, accelerated depreciatio had the most effect on those technologies with short tax lives. (Hydro is similarly affecte because of the large change in its tax life, from 20 to 50 years.)

Accelerated depreciation lowers levelized costs because it lowers taxes to th utility in the early years. For tax purposes, the project has much higher depreciatio expenses in the early years, which lowers the utility's tax payments. After the ta depreciation life is past, tax payments are higher because there is no depreciation t lower taxable income. The total taxes paid are generally the same over the life of th plant, but because of the time value of money, the accelerated depreciation is still a ne benefit. Lower taxes early in the plant life more than offset the higher taxes later. Ther is an added factor due to normalizing tax payments that accentuates the benefit fron accelerated depreciation. This is discussed in Sect. 5.3.2.

There is a production tax credit available to the wind and biomass plantatio technologies. It is described in Sect. 4.2.7. In Fig. 5.4 and Table 5.3, we show that th credits are a significant benefit to the cost of the technologies. The production tax credi lowers the cost of wind power 27% and the biomass plantation by 17%. Both of th technologies have "prices" low enough in every year to take full advantage of the 1.5 credit. (The model divides the calculated required revenue by the production amount t determine a quasi-price for the plant.) The wind plant is most affected on a percentag basis because of its lower base cost. For both technologies, the reduction in levelize cost is 1.24¢/Kwh. Actually, the credit alone is worth only 0.75¢/kWh in levelized cos reduction, because of the 10 year life of the credit, but the synergistic effect on prices an

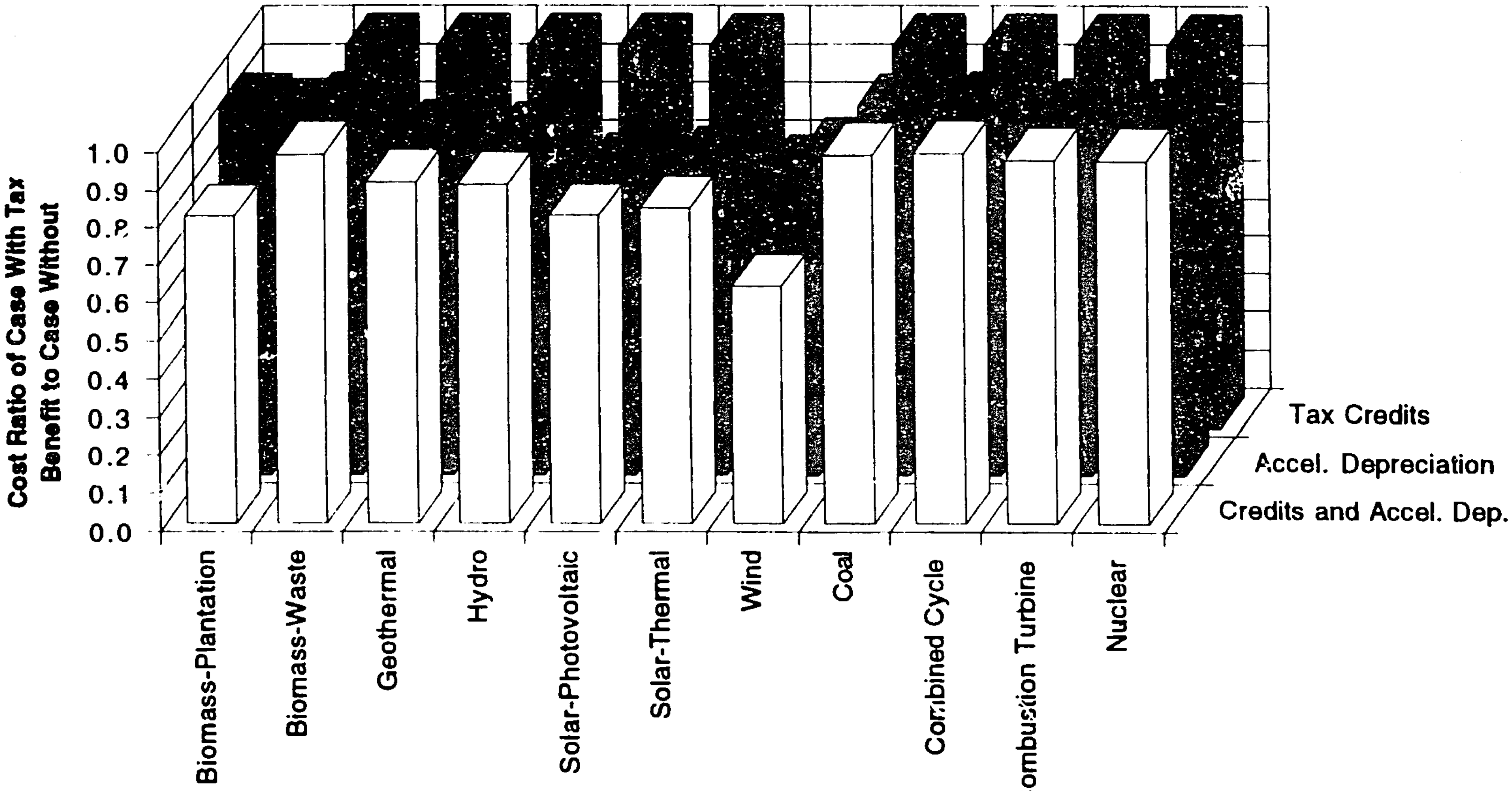
Table 5.3
Summary of Federal Income Tax Effects on Levelized Cost and Internal Rate of Return, Investor-Owned Utilities

(Ratio of Case with Tax Policies to Case Without)

Generating Type	Effect of Including Income Taxes and Credits	Effect of Including Accelerated Depreciation	Effect of Including Federal Tax Credits	Effect of Including Accel. Depreciation and Tax Credits
RENEWABLES				
Biomass-Plantation				
Levelized Cost	0.85	0.97	0.83	0.81
Int. Rate of Return	0.99	0.99	1.00	0.99
Biomass-Waste				
Levelized Cost	1.03	0.97	1.00	0.97
Int. Rate of Return	0.99	0.99	1.00	0.99
Geothermal				
Levelized Cost	0.98	0.90	1.00	0.90
Int. Rate of Return	0.96	0.95	1.00	0.95
Hydro				
Levelized Cost	1.04	0.90	1.00	0.90
Int. Rate of Return	0.98	0.98	1.00	0.98
Solar-Photovoltaic				
Levelized Cost	0.95	0.81	1.00	0.81
Int. Rate of Return	0.95	0.94	1.00	0.94
Solar-Thermal				
Levelized Cost	0.95	0.83	1.00	0.83
Int. Rate of Return	0.95	0.94	1.00	0.94
Wind				
Levelized Cost	0.71	0.81	0.73	0.62
Int. Rate of Return	0.95	0.95	1.00	0.95
CONVENTIONAL				
Coal				
Levelized Cost	1.04	0.97	1.00	0.97
Int. Rate of Return	0.99	0.99	1.00	0.99
Combined Cycle				
Levelized Cost	1.03	0.98	1.00	0.98
Int. Rate of Return	0.99	0.99	1.00	0.99
Combustion Turbine				
Levelized Cost	1.02	0.96	1.00	0.96
Int. Rate of Return	0.98	0.98	1.00	0.98
Nuclear				
Levelized Cost	1.03	0.96	1.00	0.96
Int. Rate of Return	0.98	0.98	1.00	0.98

Note: The tax effects are the ratios of the levelized costs and IRRs of the cases with the tax policies in effect to the cases without the tax policies. Levelized cost ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives. IRR ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

Figure 5.4
Effect of Accelerated Depreciation and Tax Credits on Levelized Cost, Investor-Owned Utilities



income taxes lowers the levelized cost a further 64%, to 1.24¢/kWh. This effect is explained in Appendix A.

Section 1916 of the Energy Policy Act permanently extends the energy investment credit for solar and geothermal property. However, the tax code was changed in 1992 prior to EPACT such that public utilities are not eligible for this credit. Since NUG's can take the credit, this creates a tax advantage for NUG development of these technologies rather than IOU's.

The final column in Table 5.3 lists the effect of accelerated depreciation and the tax credits together. We ran a set of cases using book depreciation and no credits, and found that the levelized costs rose for all cases, compared to the reference cases. By dividing the reference cost by this higher cost we find that the combined effect is roughly equal to multiplying the effect of each together.

5.2.2. Property Tax Effects

The effects of property taxes are shown in Table 5.1 above. Property taxes affect the capital-intensive renewable technologies (hydro, solar, wind) much more than the conventional technologies, with costs raised from 20% to 30%. Because much of the costs for the renewables are capital-related, as opposed to fuel- or operating-related, a higher proportion of their cost is subject to the tax. In addition, the property tax declines over time as the plant is depreciated. This means the cost from property tax is "front-loaded", with higher payments early in the life of the plant, which in turn have a higher weighting when levelizing the cost due to the discount rate.

To understand the effect of different methods for calculating the property tax base we used two other methods, gross book value and the net present value of the future cash flow stream. Also, we studied the effect of charging property tax on the added plant and equipment but not on the original land value. The results are shown in Table 5.4 and Fig. 5.5. When compared to the no-property-tax scenario, all have roughly the same result: a much higher impact on the capital-intensive renewables than on the conventionals. Since the cost of land was set at only 5% of total capital cost (except in the case of wind technology, where it is set at 10%), the effect of exempting land from the property tax is not large. The conventionals and biomass technologies had their overall costs lowered less than 1% by exempting land, while solar and hydro technologies dropped around 1.5%, and wind 2.7%.

5.2.3. Input Tax Effects

We show the effect of taxes on the inputs to production (labor, energy, material, and land) in Table 5.5. Most technologies show an overall effect from input taxes of around 7% of the levelized cost. Input taxes have a slightly larger effect on wind plants because the production tax credits lower the underlying cost of both scenarios. The input taxes are thus a higher percentage of the remaining cost. If the production tax credit is eliminated from both the reference and the no-input-tax scenario, the effect of input taxes on wind becomes only 7%, similar to the other technologies.

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Table 5.4
Summary of Property Tax Effects on Levelized Cost and Internal Rate of Return, Investor-Owned Utilities

(Ratio of Alternative Scenarios to No Property Tax Scenario)

Generating Type	Effect of Tax Based on Net Book Value (Reference)	Effect of Tax Based on Gross Book Value	Effect of Tax Based on Future Cash Flow	Effect of Tax Based on Net Book Value + No Tax on Land
RENEWABLES				
Biomass-Plantation				
Levelized Cost	1.09	1.14	1.09	1.08
Int. Rate of Return	1.00	1.00	1.00	1.00
Biomass-Waste				
Levelized Cost	1.08	1.13	1.08	1.07
Int. Rate of Return	1.00	1.00	1.00	1.00
Geothermal				
Levelized Cost	1.11	1.18	1.09	1.10
Int. Rate of Return	1.00	1.00	1.00	1.00
Hydro				
Levelized Cost	1.24	1.35	1.24	1.22
Int. Rate of Return	1.00	1.00	1.00	1.00
Solar-Photovoltaic				
Levelized Cost	1.27	1.44	1.20	1.25
Int. Rate of Return	1.00	1.00	1.00	1.00
Solar-Thermal				
Levelized Cost	1.23	1.37	1.17	1.21
Int. Rate of Return	1.00	1.00	1.00	1.00
Wind				
Levelized Cost	1.31	1.48	1.24	1.26
Int. Rate of Return	1.00	1.00	1.00	1.00
CONVENTIONAL				
Coal				
Levelized Cost	1.09	1.15	1.10	1.08
Int. Rate of Return	1.00	1.00	1.00	1.00
Combined Cycle				
Levelized Cost	1.07	1.12	1.07	1.07
Int. Rate of Return	1.00	1.00	1.00	1.00
Combustion Turbine				
Levelized Cost	1.09	1.14	1.08	1.08
Int. Rate of Return	1.00	1.00	1.00	1.00
Nuclear				
Levelized Cost	1.09	1.14	1.09	1.08
Int. Rate of Return	1.00	1.00	1.00	1.00

Note: Effects are the ratios of the levelized costs and IRRs of the cases with the listed property tax method to the case with no property taxes. Levelized cost ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives. IRR ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

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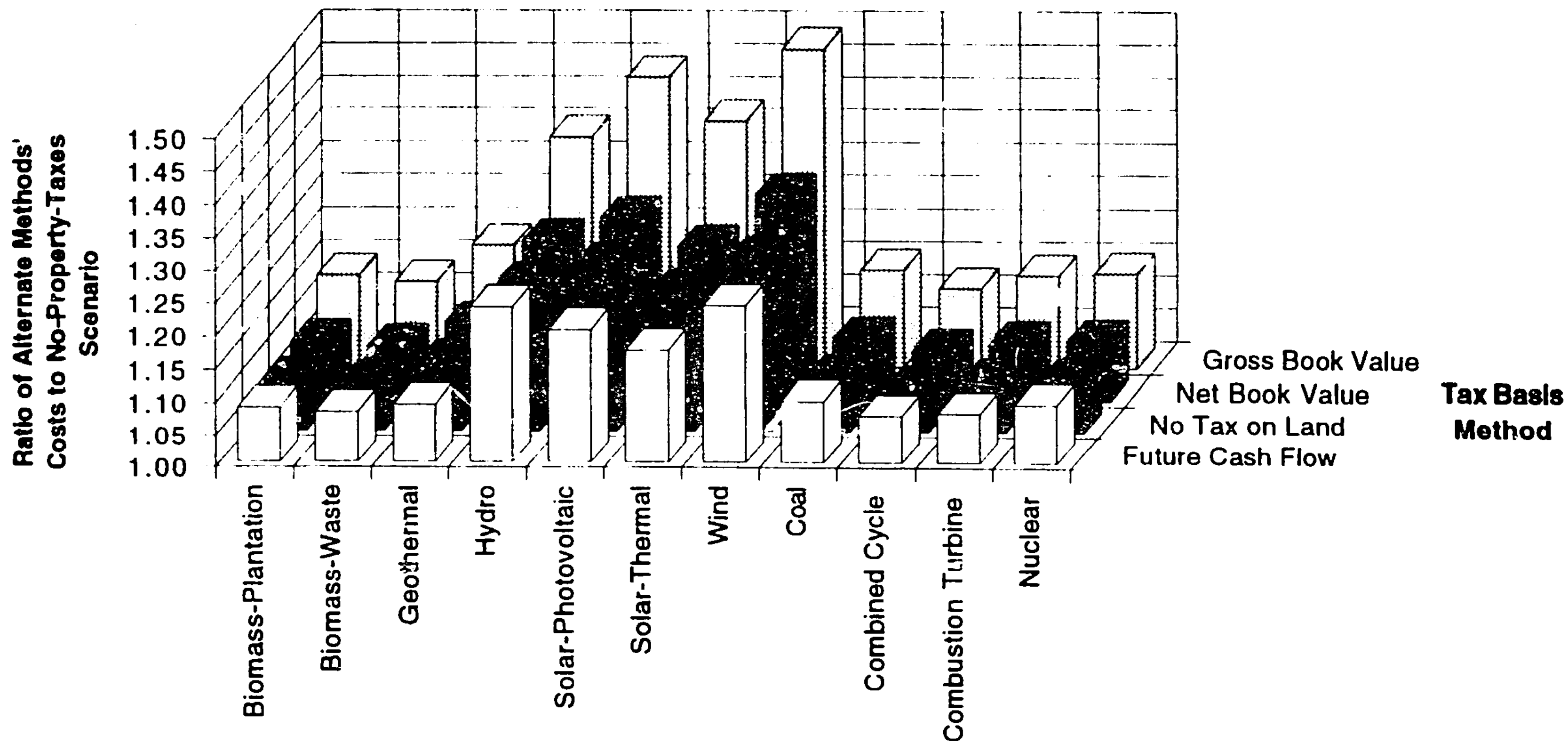
Figure 5.5
Effect of Property Tax Methods on Levelized Cost,
Investor-Owned Utilities



Ratios greater than 1.0 indicate barriers

Table 5.5
Summary of State Input Tax Effects on Levelized Cost and Internal Rate of Return, Investor-Owned Utilities

(Ratio of Case with Taxes to Case Without)

Generating Type	Effect of All Input Taxes	Effect of Labor Taxes	Effect of Fuel Taxes	Effect of Material Taxes	Effect of Land Taxes
RENEWABLES					
Biomass-Plantation					
Levelized Cost	1.07	1.02	1.03	1.01	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Biomass-Waste					
Levelized Cost	1.06	1.02	1.02	1.01	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Geothermal					
Levelized Cost	1.07	1.04	1.00	1.02	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Hydro					
Levelized Cost	1.07	1.04	1.00	1.02	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Solar-Photovoltaic					
Levelized Cost	1.07	1.04	1.00	1.02	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Solar-Thermal					
Levelized Cost	1.07	1.04	1.00	1.02	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Wind					
Levelized Cost	1.10	1.06	1.00	1.03	1.01
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
CONVENTIONAL					
Coal					
Levelized Cost	1.07	1.03	1.02	1.02	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Combined Cycle					
Levelized Cost	1.06	1.02	1.03	1.01	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Combustion Turbine					
Levelized Cost	1.06	1.02	1.03	1.01	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00
Nuclear					
Levelized Cost	1.07	1.04	1.01	1.02	1.00
Int. Rate of Return	1.00	1.00	1.00	1.00	1.00

Note: The tax effects are the ratios of the levelized costs and IRRs of the cases with taxes to the cases without the taxes. Levelized cost ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives. IRR ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

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We also show in Table 5.5 the results of each input tax separately. The change due to taxes on each component of the inputs is roughly proportional to the percentage each component has on the overall cost. For the capital-intensive technologies, little fuel is involved beyond that used during construction; the change is driven by the taxes on material, labor, and land. The most fuel-intensive technologies—biomass, combined cycle, and combustion turbines—are more affected by the fuel tax. With these, the fuel tax represents about half of the total impact from the taxes on inputs.

5.3. KEY RATEMAKING EFFECTS

5.3.1. CWIP in Rate Base

Allowing CWIP in the rate base raised the levelized cost for most technologies, but the effects were small, even for nuclear plants with 7-year construction periods. Hydro experienced the largest increase in cost (0.4% increase); nuclear experienced a 0.3% increase.

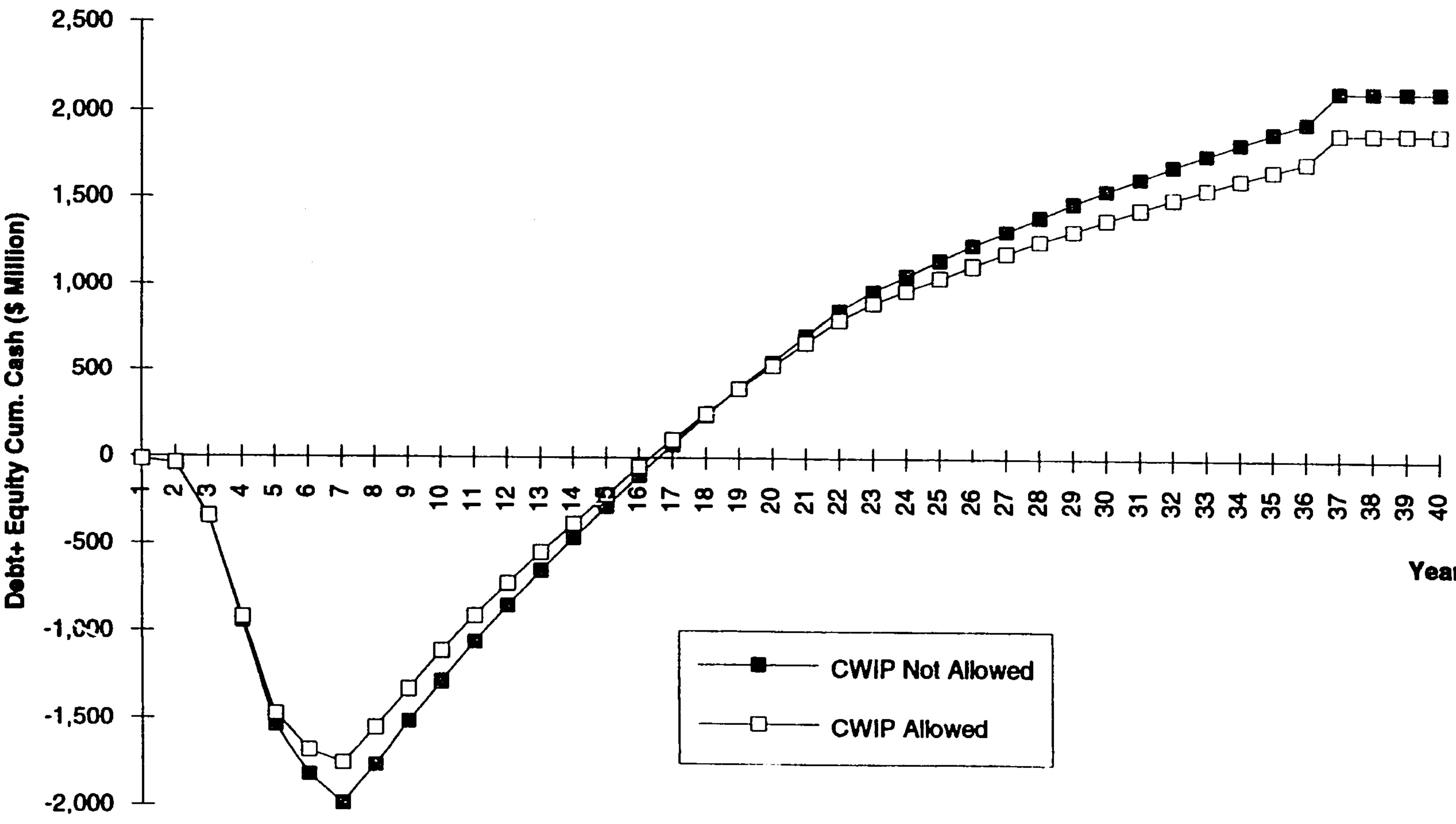
The two key decisionmaking criteria (levelized cost, IRR) are not the best indicators of CWIP's effects. They capture the costs of a project over its life but are not sensitive to the timing of the costs. The rate base formula levelizes the effects of changing the time frame when revenues are received. Revenues received early have a higher weighting in the levelized cost but lower the net investment. The decrease in net investment, in turn, lowers revenues required later during operation of the plant.

The main benefit from allowing CWIP is the reduction in net funds required from the utility during construction. For the nuclear plant, required debt and equity amounts decline 12% (see Fig. 5.6). However, the short construction schedule of the renewable technologies mean that the utility does not see as much of a benefit from CWIP. The capital requirement for the wind plant (with a 2-year construction) is reduced only 1.3%. Even the biomass plant, with a 4-year schedule, has only a 5% reduction in the maximum capital investment. In real-world applications, a utility may see its bond ratings improve and consequent interest rate on debt decline because of the lower capital exposure, but we did not analyze the effect in this study.

5.3.2. Tax Flow-Through Effects

As shown above in Table 5.2, allowing customers to benefit from the favorable provisions of federal tax laws immediately has an unfavorable effect on levelized cost. There are two factors to be considered. First, tax laws require that if flow-through accounting for tax benefits is used rather than normalization, the tax depreciation lives of the assets must be increased by a statutory amount. Assets with deprecation lives of 5 years must be increased to 12; those with 15 years to 20; and those with 20 to 28 years. Hydro must extend its tax life to 50 years. Of course, technologies with the largest increase in tax lives are most affected by this provision of the tax laws. For example, changing the tax life for solar-photovoltaic from 5 to 12 years increases its levelized cost by 6%. Hydro is more adversely affected by the change; its cost increases by 10% if its tax depreciation life is changed from 20 to 50 years. Dedicated-plantation biomass, which

Figure 5.6
Effect of CWIP Allowance on
Cumulative Debt and Equity Cash Flow,
IOU Nuclear Plant



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experiences a tax life increase from 20 to 28 years under flow-through accounting, experiences a cost increase of only 2.0%.

The other factor explaining the effects of normalization is that taxes are collected from customers that are deferred, or paid to the government some years later. These tax deferrals can be from accelerated depreciation or allowance for borrowed funds during construction. Customers pay higher prices early in the plant life, but pay less later. These advance payments are used to lower the amount of equity in the plant by creating a deferred tax liability. Because customers do not have to pay any return on this amount, their prices are lowered.

Fig. 5.7 depicts the revenues paid by the customers for a geothermal plant under three scenarios: (1) normalized taxes, (2) flow-through with a 5-year tax depreciation life, and (3) flow-through with the required 12-year tax life. Before the plant begins operation, customers pay nothing under normalization and actually get a small rebate under flow-through because of the tax reduction for interest expense. As the plant begins operation, the normalized revenue requirements are high because deferred taxes raise the cost to customers. The flow-through cases have low revenue requirements in the first few years because the accelerated depreciation greatly reduces the tax cost. However, their revenue requirements are soon higher than the normalized case because under normalization, the deferred tax liability builds up and lowers the rate base. The tax flow-through cases have a sudden jump as the plant finishes its tax life. Discounting these revenue streams shows that the flow-through cost with 12 year depreciation is 6% higher than the normalized cost. Even using the 5 year depreciation life, the levelized cost of flow-through is 4% higher than the normalized case.

5.4. SENSITIVITY TO INPUT ASSUMPTIONS

All of the results shown in Tables 5.1 through 5.5 are based on the values that we used to quantify the parameters of the technologies. Those values are contained in Tables 3.1 through 3.3 of Sect. 3. The data quantifying the parameters of each of the 11 technologies in those tables are "conventional wisdom" today. That is, the financial costs, engineering characteristics, and assigned work loads (i.e., capacity factors) of the technologies are reasonable estimates of what a "representative" electric utility would confront today.

Clearly, changing these input assumptions would affect the base values of the levelized cost and IRR, the decisionmaking criteria used in this study. To show this, we conducted a sensitivity study of the assigned values for key parameters. The results of some of these sensitivities are shown in Tables 5.6 and 5.7. The ratio of levelized costs between cases with and without specific tax and ratemaking procedures are shown both for a technology using the assumed input parameter and with a variation to that parameter. Rather than show the results for all technologies, one renewable and conventional are shown. The summary tax and ratemaking procedures from Tables 1.1 and 1.2 are shown; the values for the cases labeled "reference" are from those tables.

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Figure 5.7
Effect of Flowing Taxes Through the Rate Base on Annual Ratepayer Payments, IOU Geothermal Plant

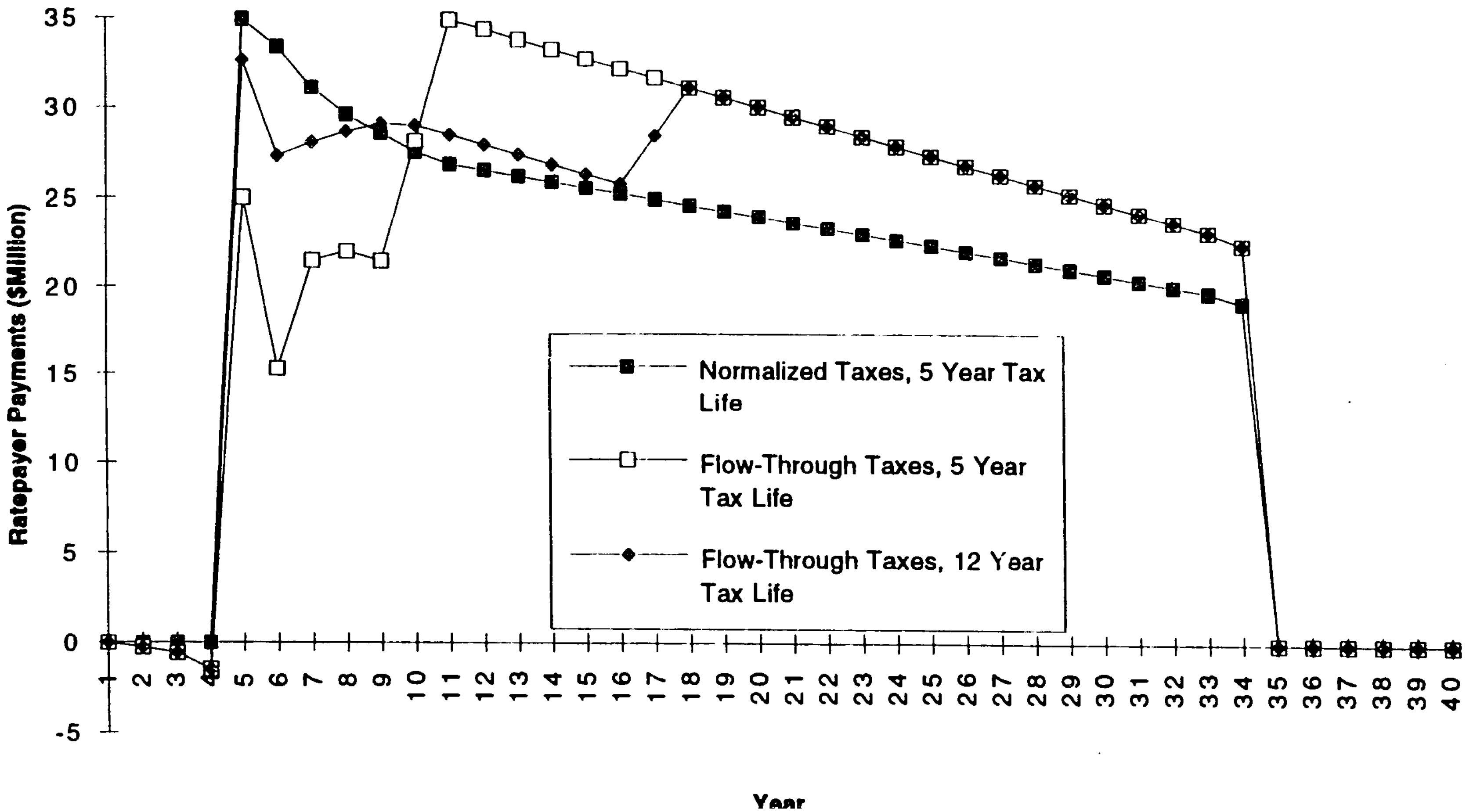

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Table 5.6
Summary of Sensitivity Analyses on Input Assumptions, Tax Effects on Levelized Costs, Investor-Owned Utilities

(Cost Ratio of Case with Taxes to Case without Taxes)

Generating Type	Effect of Including All Taxes and Credits	Effect of Including Property Taxes	Effect of Including Input Taxes	Effect of Including State Income Taxes	Effect of Including Federal Taxes and Credits
Geothermal - Reference	1.16	1.11	1.07	1.00	0.98
Geothermal - Extended Construction Sched.	1.17	1.11	1.07	1.00	0.98
Nuclear - Reference	1.20	1.09	1.07	1.00	1.03
Nuclear - Extended Construction Schedule	1.20	1.08	1.07	1.01	1.04
Solar/Thermal - Reference	1.24	1.23	1.07	0.99	0.95
Solar/Thermal - Low Capital Cost	1.23	1.22	1.07	0.99	0.96
Coal - Reference	1.22	1.09	1.07	1.01	1.04
Coal - Low Capital Cost	1.20	1.08	1.06	1.01	1.03
Wind - Reference	0.91	1.31	1.10	0.97	0.71
Wind - Low Capacity Factor	1.01	1.30	1.09	0.98	0.78
Combustion Turbine - Reference	1.18	1.09	1.06	1.00	1.02
Com. Turbine - Low Capacity Factor	1.24	1.13	1.06	1.00	1.03
Wind - Reference	0.91	1.31	1.10	0.97	0.71
Wind - 4% Inflation	0.91	1.29	1.10	0.97	0.71
Coal - Reference	1.22	1.09	1.07	1.01	1.04
Coal - 4% Inflation	1.22	1.08	1.06	1.01	1.05

Ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives.

Table 5.7
Summary of Sensitivity Analyses on Input Assumptions, Ratemaking Effects on Levelized Costs, Investor-Owned Utilities

(Cost Ratio of Case with Ratemaking Procedure to Case Without)

Generating Type	Effect of Not Including CWIP in Rate Base	Effect of Normalizing Taxes in Rate Base	Effect of Automatic Fuel Adjustments
Geothermal - Reference	1.00	0.94	1.00
Geothermal - Extended Construction Sched.	1.00	0.94	1.00
Nuclear - Reference	1.00	0.97	1.00
Nuclear - Extended Construction Schedule	0.99	0.97	1.00
Solar/Thermal - Reference	1.00	0.90	1.00
Solar/Thermal - Low Capital Cost	1.00	0.90	1.00
Coal - Reference	1.00	0.98	1.00
Coal - Low Capital Cost	1.00	0.98	1.00
Wind - Reference	1.00	0.89	1.00
Wind - Low Capacity Factor	1.00	0.89	1.00
Combustion Turbine - Reference	1.00	0.98	1.00
Com. Turbine - Low Capacity Factor	1.00	1.03	1.00
Wind - Reference	1.00	0.89	1.00
Wind - 4% Inflation	1.00	0.88	1.00
Coal - Reference	1.00	0.98	1.00
Coal - 4% Inflation	1.00	1.02	1.00

Ratios greater than 1.0 indicate barriers; ratios less than 1.0 indicate incentives.

As an example, one concern mentioned has been that the construction time may greatly influence the results. We extended the construction time for the geothermal plant from four years to six years and the nuclear technology from seven years to fifteen years. As can be seen in Tables 5.6 and 5.7, the relative impact of taxes and ratemaking on these technologies barely changed.

As another example, reducing the capital cost of the coal option by 20% from $1,512/kW to $1,210/kW lowers the levelized cost of the coal option from $5.90/kWh to $5.34/kWh. However, our basic conclusions on ratemaking and taxation barriers to and incentives for adopting the coal technology do not change. The values only change slightly between the reference assumptions and the lower capital cost cases. Similarly, reducing the capital cost of a solar/thermal plant by 20% does not alter our conclusions about barriers and incentives for solar/thermal.

Another important variable for each of the 11 technologies is the assigned capacity factor. The capacity factors are based on our assumptions about the work load of the technologies and, ultimately, about the relationship between their capital and operating costs. For example, a utility would not construct a nuclear plant for peak-load purposes, and therefore, we assign the nuclear option a 70% base-load capacity factor. Assuming a 10% capacity factor for a nuclear plant—as we assumed for the combustion turbine unit—would seriously distort our picture of the financial performance of the plant. A similar argument can be made for running a combustion turbine as a base-load unit. Again, however, changing capacity factors for both technologies in the sensitivity study does not alter our conclusions about barriers and incentives.

Recognizing that simulation results for the 1.5¢/kWh production tax credit for dedicated-plantation biomass and wind technologies are based directly on the capacity factors assumed in Table 3.1, we also ran sensitivity studies on these values. Again, our overall conclusions on barriers and incentives do not change. For example, reducing the capacity factor of wind from 30% (Table 3.1) to 20% reduces the production tax credit allowed for wind substantially because the credit is based on kilowatt-hour generation. Except for the case with all taxes removed, our conclusions on ratemaking and taxation as barriers or incentives for wind are not changed.

To check the effect of inflation, we ran all of the cases using a 4% inflation rate, as opposed to 0% (constant dollars) for the reference cases. The results for the wind technology and the coal plant are shown in Tables 5.6 and 5.7. There was very little effect from inflation on any of the tax or ratemaking policies. The effect from property taxes was significant until it was realized that the model understated assessed property values under inflation. Net book value (the method used) is a good approximation of assessed value under constant dollars, but in inflationary times the value would be reassessed periodically. To model this in the property tax calculation, we increased the net book value by the amount of inflation since plant start-up. The results in Table 5.6 show a reduction in the effect of property taxes on cost from 1.31 to 1.29.

The reason that there is little change in conclusions in all of the cases above is because we are not comparing costs of technologies with one another but, rather, examining the effects of ratemaking and taxation procedures on a given technology. Changes to the plant parameters effect the cases both with and without the tax or ratemaking policy. As Tables 5.6 and 5.7 show, conclusions about barriers and incentives drawn from the process used in this study are robust across wide values of the variables shown in Tables 3.1, 3.2, and 3.3.

An important ratemaking assumption derived from the assumptions in Sect. 3 is the effect of fuel costs on rates. In our scenarios dealing with fuel costs, we assume in the reference scenario that annual increases in fuel costs (Table 3.3) are passed along to the customer on an annual basis. In the alternative scenario for fuel adjustment clauses, payment of fuel cost increases lagged one year for ratemaking purposes. In both these scenarios, we assume that all fuel cost increases are ultimately borne by ratepayers.

To see the effect of this assumption on our results, we conducted a sensitivity study on the assumed increase of natural gas prices. As indicated in Table 3.3, gas prices are assumed to increase at an annual rate of 3.2%. In our sensitivity study, we assume the same 3.2% growth in natural gas prices for the two technologies using natural gas (i.e., combustion turbine and combined cycle), but further assume that only 2.2% is allowed to be passed along to ratepayers with the remaining 1% being borne by stockholders. This is an extreme case because it implies that by the end of the plant's life, customers are only paying 75% of the total fuel cost.

The results of this sensitivity study are significant. For a combustion turbine plant, the levelized cost decreases by nearly 1¢/kWh because ratepayers are exposed to only 2.2% annual growth. However, because equity holders must now bear 1% of the annual natural-gas price increase, the IRR-equity for a combustion turbine declines from the commission-allowed 7.0% to a negative return. The total IRR (i.e., debt + equity) declines from 5.85% to 2.74%. For a combined cycle plant, the same assumptions show that the levelized cost drops by 6 mils, the internal rate of return-equity drops from 7.0% to a negative return, and the total IRR declines from 5.91% to 2.94%.

6. SIMULATION RESULTS FOR NONUTILITY GENERATORS

6.1. SUMMARY

Because NUGs are not subject to rate-of-return regulation in a manner similar to IOUs, we only consider the effects of tax measures on NUGs. Therefore, levelized cost is not used as a decisionmaking criterion. Instead, we use the internal rate of return (IRR) as the primary criterion. This variable indicates the overall return of the project to its investors, both debt and equity holders. We also use the IRR for equity shareholders alone as another criterion. However, its changes are more extreme and are dependent on details of the financing structure of the NUG which are beyond the scope of this study. Both criteria are defined in more detail in Appendix A.

In Table 6.1 we show the results of the tax policy scenarios. A reference scenario was established which included all current tax policies. Subsequently each specific tax policy was removed from the reference scenario to find its effect. The numbers in Table 6.1 show the ratio of the criterion (IRR, IRR-Equity) with the tax policy to the criterion without the policy. In most cases, this is the value from the reference scenario divided by the value from the sensitivity scenario. (The alternative minimum tax (AMT) data in the table have the reference scenario in the denominator since it did not include this tax policy.) The raw values of the output criteria are in Appendix B. Many of the results directly parallel the results for utilities (Sect. 5).

The first variation to the reference case was to run each technology with no taxes or credits of any kind. The changes in the project IRR can be seen in Fig. 6.1. For conventionals, the net effect of taxes is to lower the IRR by roughly 40%. Renewables, on the other hand, have a more varied response to taxes. While hydro and waste wood biomass facilities show effects from taxes similar to those of conventional technologies, the other renewables are not as affected. Dedicated biomass and wind plants actually show a net positive impact from taxes (i.e., higher IRR). To see why, each tax policy must be analyzed in turn.

The effects of property taxes alone are shown next in Table 6.1. For the NUG scenarios, both the property taxes and the annual net cash flow (which defines the IRR) are functions of the capital-intensiveness of the technology. Consequently, loss of property taxes has roughly the same proportionate effect on the IRR of low capital-intensive and high capital-intensive technologies.

We next show the effect of taxes on the inputs to production (labor, energy, material, and land) in Table 6.1. There is some variation based partly on the capital-intensiveness of the project. The technologies with high ratios of capital to fuel or O&M costs are less affected by the taxes on inputs.

State income tax effects were examined next. The change in IRR due to the 6% tax was small but positive for several renewables. The two that receive the production tax credit were affected the most. The contract price per kWh used to determine revenues of the NUG are based on the levelized cost from the IOU reference cases that provided the utility with a 7% return on equity. The IOU versions of these two technologies (wind

Table 6.1
Summary of Tax Effects on
Internal Rate of Return and Internal Rate of Return-Equity,
Nonutility Generators

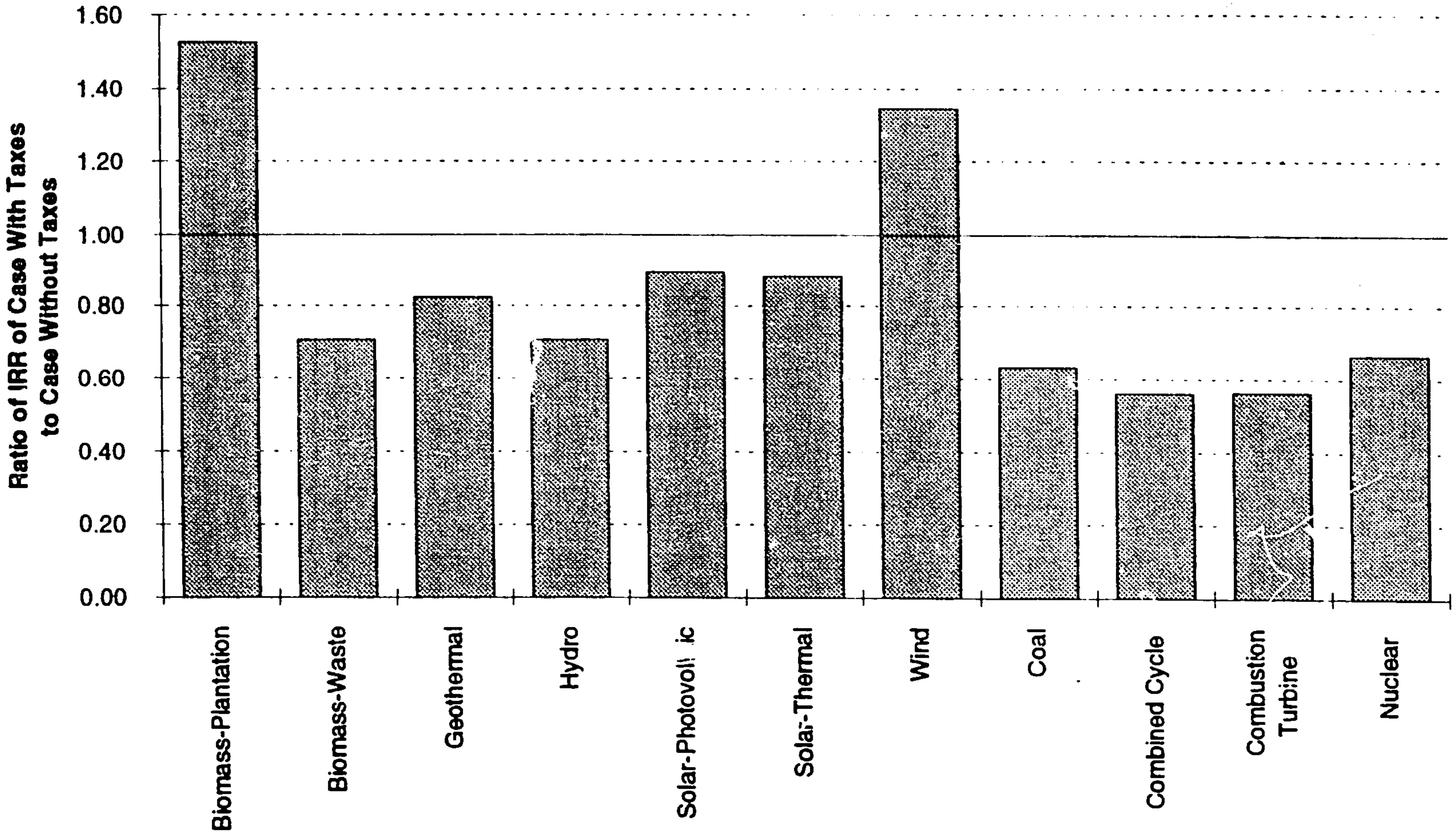
(Ratio of IRRs of Case with Tax Policies to Case Without)

Generating Type	Effect of Including All Taxes and Credits	Effect of Including Property Taxes	Effect of Including Input Taxes	Effect of Including State Income Taxes	Effect of Including Federal Taxes and Credits	Effect of Including Alternative Minimum Tax
RENEWABLES						
Biomass-Plantation						
Int. Rate of Rtrn	1.53	0.81	0.83	1.05	5.56	0.68
IRR - Equity	4.89	0.82	0.85	1.11	a	0.35
Biomass-Waste						
Int. Rate of Rtrn	0.71	0.82	0.86	1.01	1.06	0.77
IRR - Equity	0.83	0.71	0.79	1.08	1.66	0.43
Geothermal						
Int. Rate of Rtrn	0.82	0.81	0.87	1.02	1.29	0.75
IRR - Equity	1.33	0.74	0.84	1.12	3.19	0.33
Hydro						
Int. Rate of Rtrn	0.71	0.83	0.93	1.00	0.99	0.91
IRR - Equity	0.57	0.66	0.86	1.01	1.07	0.77
Solar-Photovoltaic						
Int. Rate of Rtrn	0.90	0.79	0.92	1.02	1.38	0.71
IRR - Equity	2.12	0.73	0.92	1.16	5.53	5.32
Solar-Thermal						
Int. Rate of Rtrn	0.89	0.79	0.91	1.02	1.38	0.71
IRR - Equity	2.07	0.73	0.90	1.16	5.44	5.17
Wind						
Int. Rate of Rtrn	1.35	0.75	0.88	1.06	3.58	0.65
IRR - Equity	5.91	0.71	0.86	1.20	a	a
CONVENTIONAL						
Coal						
Int. Rate of Rtrn	0.64	0.84	0.87	0.99	0.93	0.97
IRR - Equity	0.49	0.69	0.77	0.99	0.93	0.91
Combined Cycle						
Int. Rate of Rtrn	0.56	0.80	0.83	0.99	0.90	0.98
IRR - Equity	0.45	0.68	0.75	0.98	0.85	0.95
Combustion Turbine						
Int. Rate of Rtrn	0.56	0.78	0.83	0.99	0.96	0.94
IRR - Equity	0.45	0.64	0.75	1.00	1.01	0.86
Nuclear						
Int. Rate of Rtrn	0.67	0.85	0.87	0.99	0.96	0.94
IRR - Equity	0.55	0.71	0.77	1.00	1.01	0.85

Ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

a Internal Rate of Return-Equity cannot be calculated for these cases because the equity cash flow profile is such that no discount rate will give a zero net present value over the entire life of the project.

Figure 6.1
Effect of All Taxes and Credits on IRR,
Nonutility Generators



Ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers

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and biomass plantation) received that return after using the credit to boost earnings. This means that their pre-tax income was quite low or negative, resulting in tax losses which lowered their taxes. The NUGs similarly show tax losses in the early years, resulting in negative income taxes for these projects in those years. Removing the state or federal income tax eliminates those early tax benefits and lowers the IRR.

The next tax scenario had to do with federal income tax policies. By eliminating both income taxes and credits from the reference scenario, we could determine the net effect of federal income taxes (Fig. 6.2). The impact on the renewable technologies is quite dramatic. The production and energy investment credits in combination with accelerated depreciation cause IRRs to be 30% to 400% higher than without taxes and credits. The details behind these results are discussed in more detail in Sect. 6.2.1.

Last, the impact of the AMT was analyzed. Under this law taxpayers must calculate their taxes both using the regular rate and using a lower rate but without as many tax breaks. They must then pay the higher of the two. This serves to lower the near-term benefit of accelerated depreciation, greatly reducing the IRR of the renewables with 5-year tax lives (Fig. 6.3). This policy is examined in more detail in Sect. 6.2.2.

6.2. KEY TAX EFFECTS

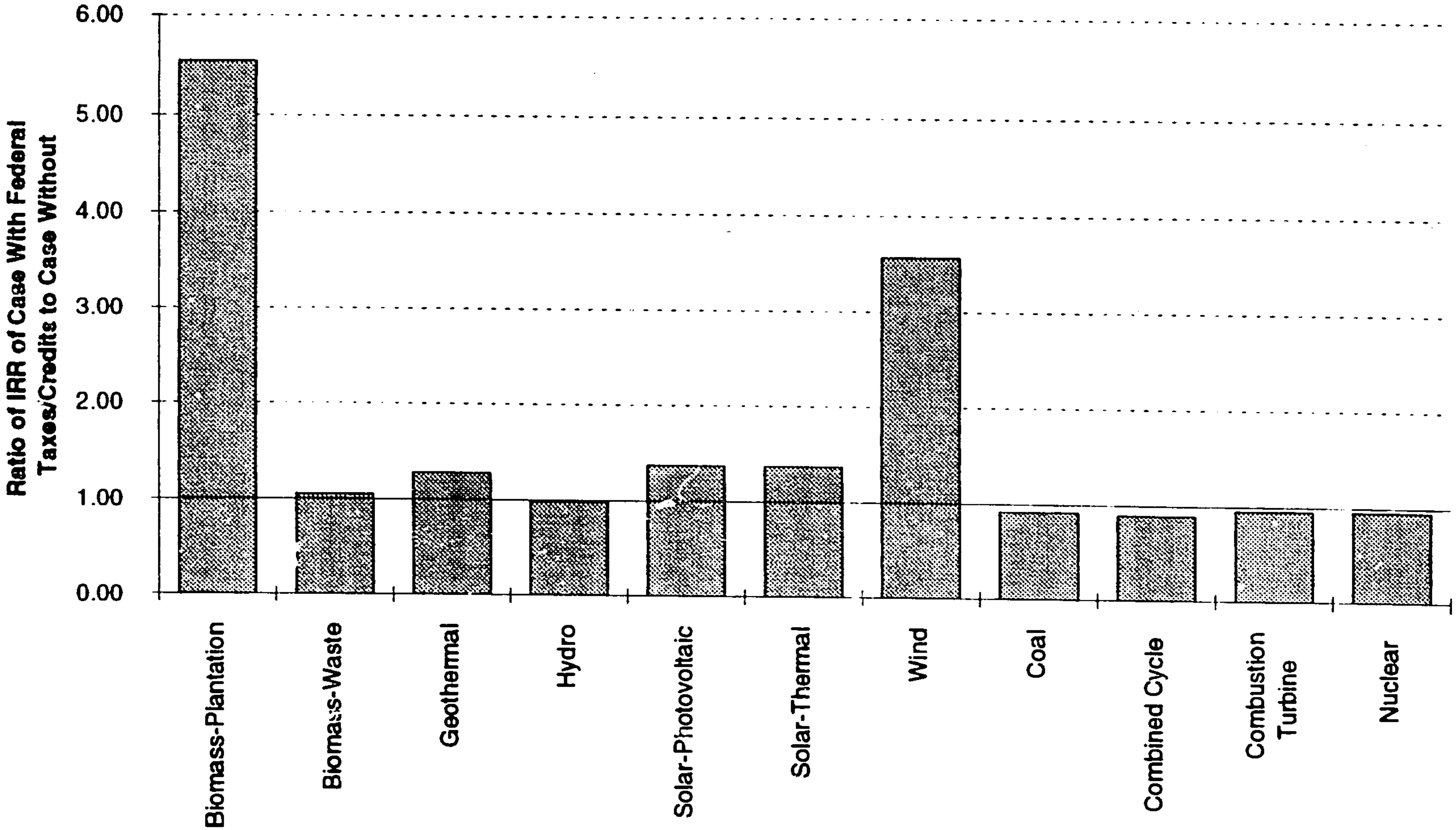
Only some of the tax effects studied had a major differentiating impact on the costs of the technologies. Of those studied, the various facets of federal income tax policy were most significant. Tax depreciation lives and the availability of tax credits seemed to be the most crucial factors. The AMT also had a large effect.

6.2.1. Federal Income Taxes and Credits

As shown in Fig. 6.2, federal tax policies play a large role in the profitability of the renewable energy technologies. There are two main factors that create this differential in profitability: accelerated depreciation and tax credits. Table 6.2 lists the results of modifying each of these parameters separately and together. In Fig. 6.4, we show the debt plus equity cash flow for the dedicated biomass plant under a set of sensitivities. As described in Appendix A, the IRR that we use as our criterion is the discount rate that makes the net present value of the cash flow equal zero.

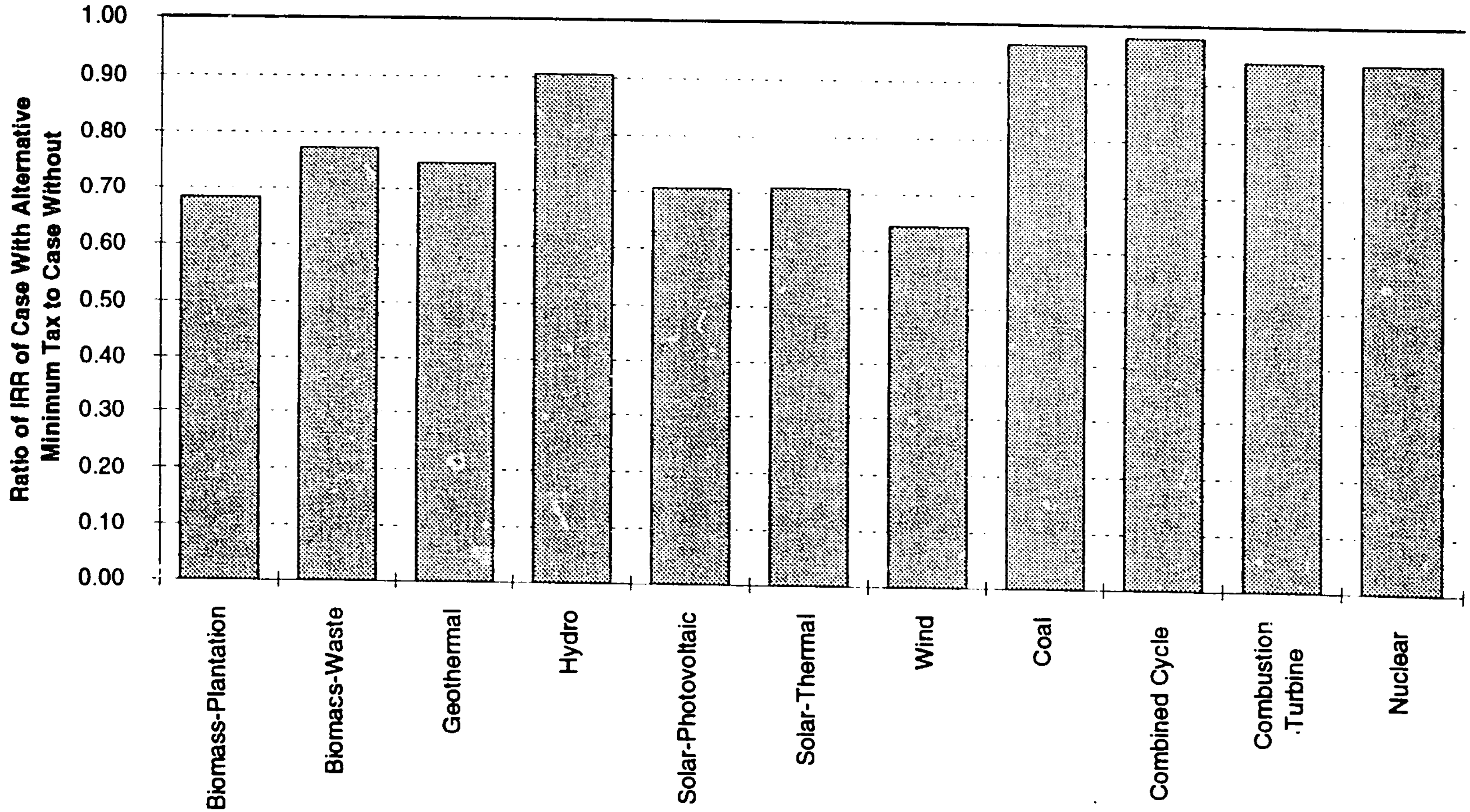
The reference scenario includes both the production tax credit and the 5-year depreciation life, as well as a 35% income tax rate. It has the highest near-term positive cash flow because of these factors and a consequent IRR of 7.9%. Without accelerated depreciation, the cash flow curve shows a smaller, flat increase for the 10 years that the production tax credit is available. Its IRR is 6.1%. With no tax credit, there is an even smaller rise in the early years, which disappears at the end of the tax depreciation life. Its IRR is 2.9%. When neither the accelerated depreciation nor credit is available, the cash flow is essentially flat because slowly declining property taxes are offset by slowly increasing income tax payments; all other cash flows are constant. The IRR becomes 2.1%.

Figure 6.2
Effect of Federal Taxes and Credits on IRR, Nonutility Generators



Ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

Figure 6.3
Effect of Alternative Minimum Tax on IRR, Nonutility Generators



Ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

Table 6.2
Summary of Federal Income Tax Effects on Internal Rate of Return and Internal Rate of Return-Equity, Nonutility Generators

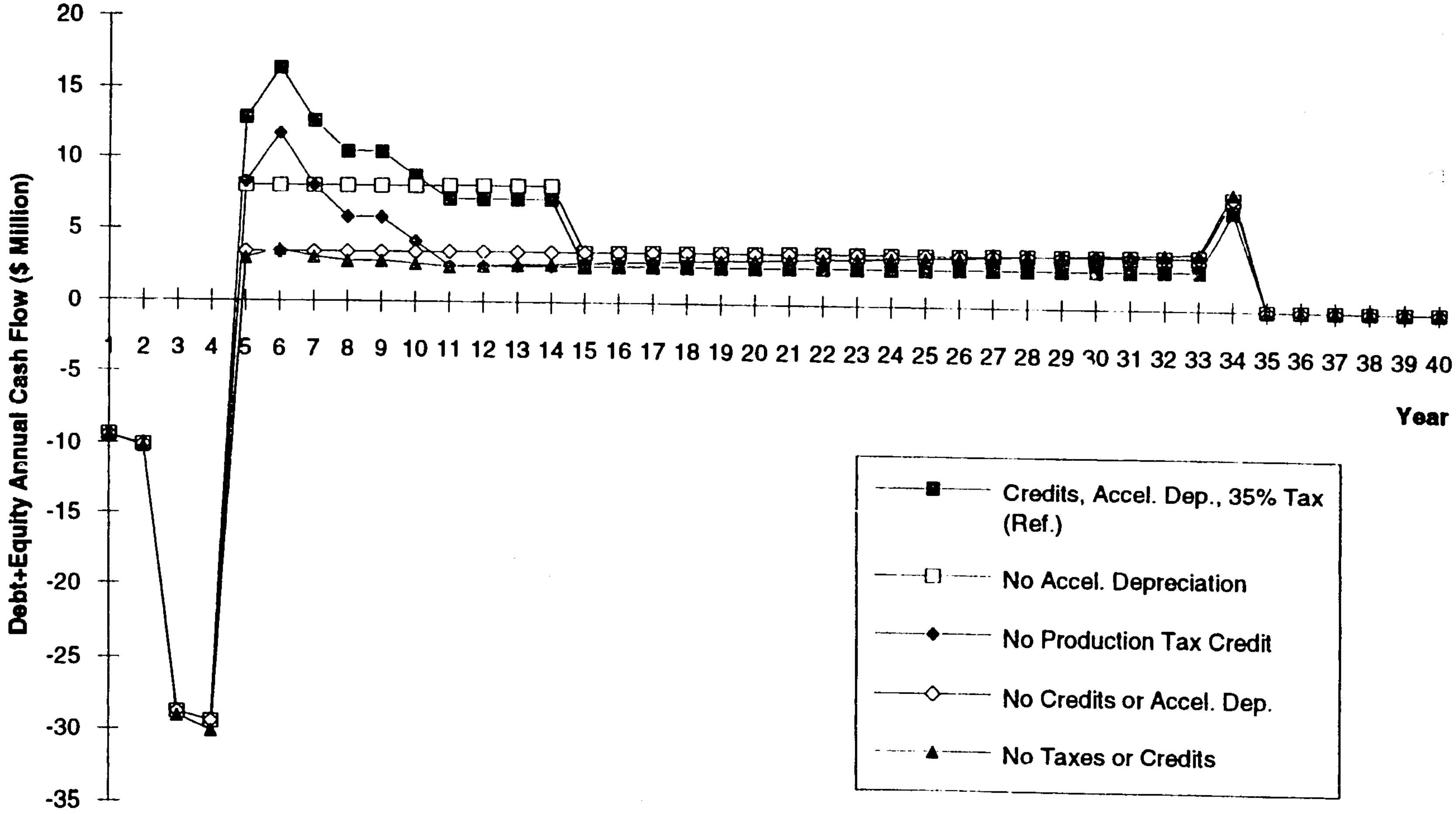
(Ratio of IRRs of Case with Tax Policies to Case Without)

Generating Type	Effect of Including Income Taxes and Credits	Effect of Including Accelerated Depreciation	Effect of Including Federal Tax Credits	Effect of Including Accelerated Depreciation and Tax Credits
RENEWABLES				
Biomass-Plantation				
Int. Rate of Retrn	5.56	1.30	2.75	3.58
IRR-Equity	a	2.47	a	a
Biomass-Waste				
Int. Rate of Retrn	1.06	1.24	1.00	1.24
IRR-Equity	1.66	2.25	1.00	2.25
Geothermal				
Int. Rate of Retrn	1.29	1.26	1.16	1.75
IRR-Equity	3.19	2.76	1.74	8.95
Hydro				
Int. Rate of Retrn	0.99	1.11	1.00	1.11
IRR-Equity	1.07	1.34	1.00	1.34
Solar-Photovoltaic				
Int. Rate of Retrn	1.38	1.30	1.19	1.53
IRR-Equity	5.53	4.37	2.27	7.53
Solar-Thermal				
Int. Rate of Retrn	1.38	1.30	1.19	1.53
IRR-Equity	5.44	4.33	2.25	7.41
Wind				
Int. Rate of Retrn	3.58	1.31	2.03	2.63
IRR-Equity	a	5.58	a	a
CONVENTIONAL				
Coal				
Int. Rate of Retrn	0.93	1.06	1.00	1.06
IRR-Equity	0.93	1.19	1.00	1.19
Combined Cycle				
Int. Rate of Retrn	0.90	1.08	1.00	1.08
IRR-Equity	0.85	1.28	1.00	1.28
Combustion Turbine				
Int. Rate of Retrn	0.96	1.15	1.00	1.15
IRR-Equity	1.01	1.72	1.00	1.72
Nuclear				
Int. Rate of Retrn	0.96	1.09	1.00	1.09
IRR-Equity	1.01	1.27	1.00	1.27

Ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

a Internal Rate of Return-Equity cannot be calculated for these cases because the equity cash flow profile is such that no discount rate will give a zero net present value over the entire life of the project.

Figure 6.4
Effect of Federal Tax Policies on Annual Debt and Equity Cash Flow, NUG Biomass Plantation



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What is surprising is that with no taxes or credits, meaning the income tax rate an credits are both zero, the IRR becomes even worse, at 1.4%. This is because the pric used, which is what the plant would cost utility customers if it were utility-owned, wa based on the utility's receiving these tax benefits. When the NUG must charge a price th gives it only a fair return (7.9%) after various tax credits are included, it is actually losin money on a tax basis before the credits. Consequently, income taxes are a net positiv cash flow; the income tax calculation shows operating losses that the owner can use t lower his taxes on other income.

In Table 6.2 we show the effect of accelerated depreciation alone on each of th technology's IRRs. As expected, those with a 5-year depreciation schedule (biomass geothermal, solar, and wind) receive the most benefit. Table 6.2 also displays the effect of the tax credits. The production tax credit (on dedicated biomass and wind) has th largest impact, more than doubling the IRR. (Both technologies have prices below th 8¢/kWh threshold, so they can use the full 1.5¢ credit.) The energy investment cred raises the IRR by roughly 20%.

6.2.2. Alternative Minimum Tax Effects

The AMT is designed to prevent taxpayers from avoiding tax liabilities because c certain tax benefits. Sect. 4.2.8 describes the tax methodology in more detail. The resu of applying the AMT is that taxes are higher in the early years of the plant's life, lowerin the debt and equity cash flow. This lowers the IRR for the project. In Fig. 6.3, we show that the effect is most pronounced on the renewable energy technologies that have a 5 year tax depreciation life. The AMT increases the life to 12 years and uses a les advantageous method for calculating depreciation.

As an example, in Fig. 6.5 we show the annual debt plus equity cash flow for th wind technology under the reference scenario and after applying the AMT. Taxes ar higher with the AMT in years 3 through 8, costing the investors a total of almost $1 million. After year 8, the regular tax calculation results in a higher tax amount and so i paid in both cases. The net result is a lowering of the IRR from 6.5% to 4.2%.

As a variant on the AMT, we also ran a scenario in which the owners did not hav other income with which they could offset the tax losses from the generating facility. Sinc the government will not pay negative taxes in the case of operating losses, the compan must use the losses to offset profits either in earlier or future years. This is calle carryback or carryforward of losses, respectively. This topic is discussed in more deta in Sect. 4.2.8.

In Table 6.3, we show the results for the reference scenario, the AMT scenario, th carryforward scenario, and the AMT plus carryforward scenario. Carryforward mos dramatically affects the technologies that have tax credits available. Since there must b positive taxes with which to offset the credits, the owners cannot use the credits until th previous tax losses are offset by positive taxes. This delays the time when they are take and thus reduces their present value. In the case of dedicated biomass and wind (wit the production tax credit), some of the tax credits are never used because of the lack o sufficient offsetting taxes.

Figure 6.5
Effect of Alternative Minimum Tax on Annual Debt and Equity Cash Flow, NUG Wind Plant

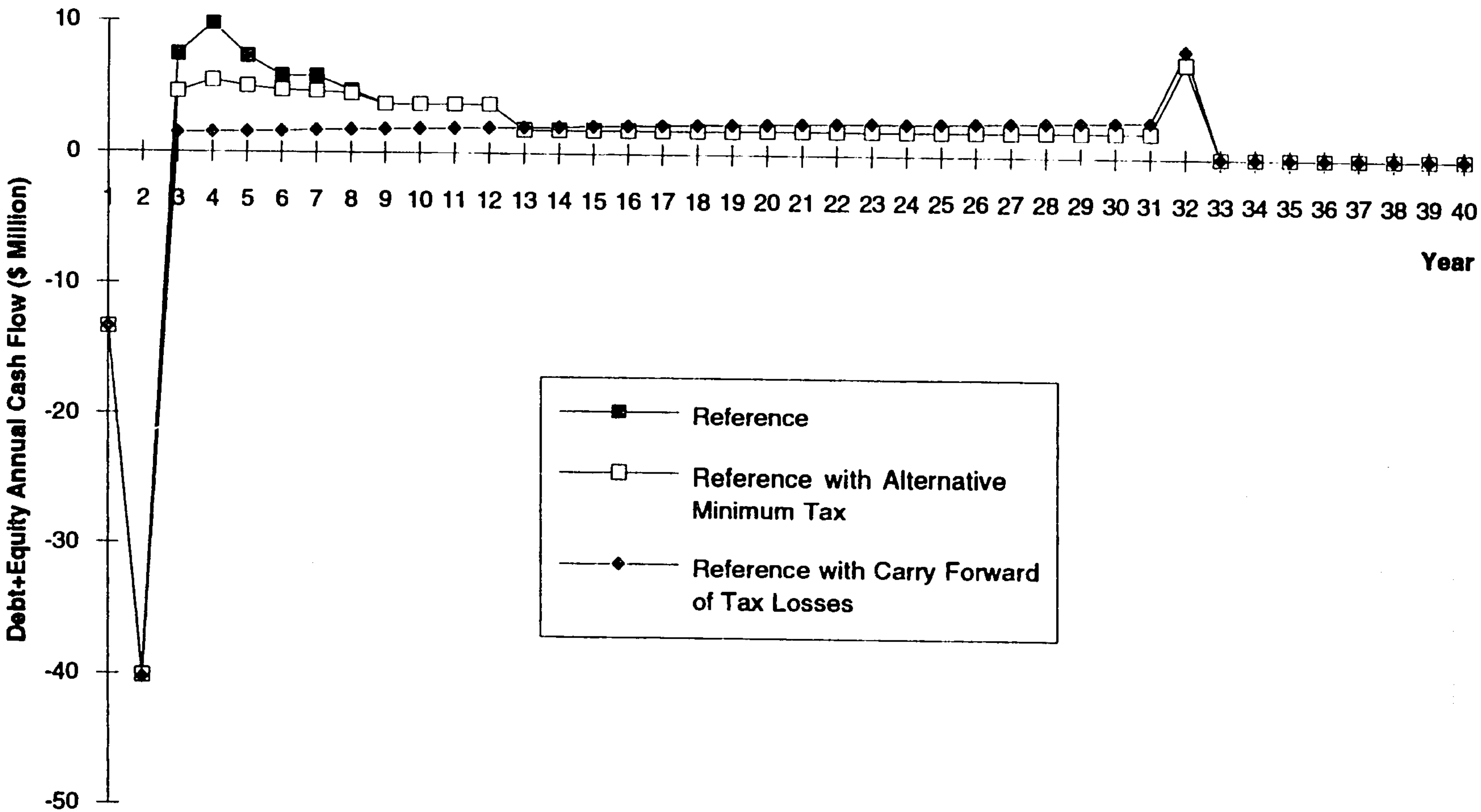

Table 6.3
Summary of Alternative Minimum Tax Effects on Internal Rate of Return and Internal Rate of Return-Equity, Nonutility Generators
(Ratio of IRRs of Case with Tax Policies to Case Without)

GENERATING ALTERNATIVE	Effect of Including Alternative Minimum Tax	Effect of Including Carryforward of Tax Losses	Effect of Including AMT and Carryforward of Losses
RENEWABLES			
Biomass-Plantation			
Int. Rate of Retrn	0.68	0.14	0.14
IRR-Equity	0.35	a	a
Biomass-Waste			
Int. Rate of Retrn	0.77	0.84	0.74
IRR-Equity	0.43	0.49	0.37
Geothermal			
Int. Rate of Retrn	0.75	0.72	0.65
IRR-Equity	0.33	0.26	0.19
Hydro			
Int. Rate of Retrn	0.91	0.92	0.89
IRR-Equity	0.77	0.79	0.73
Solar-Photovoltaic			
Int. Rate of Retrn	0.71	0.66	0.60
IRR-Equity	a	0.14	a
Solar-Thermal			
Int. Rate of Retrn	0.71	0.66	0.60
IRR-Equity	a	0.14	a
Wind			
Int. Rate of Retrn	0.65	0.24	0.24
IRR-Equity	a	a	a
CONVENTIONAL			
Coal			
Int. Rate of Retrn	0.97	0.98	0.96
IRR-Equity	0.91	0.93	0.89
Combined Cycle			
Int. Rate of Retrn	0.98	1.00	0.98
IRR-Equity	0.95	0.99	0.94
Combustion Turbine			
Int. Rate of Retrn	0.94	0.98	0.94
IRR-Equity	0.86	0.93	0.85
Nuclear			
Int. Rate of Retrn	0.94	0.94	0.92
IRR-Equity	0.85	0.83	0.79

Ratios greater than 1.0 indicate incentives; ratios less than 1.0 indicate barriers.

a Internal Rate of Return-Equity cannot be calculated for these cases because the equity cash flow profile is such that no discount rate will give a zero net present value over the entire life of the projec

In Fig. 6.5 we include the annual cash flow from the carryforward scenario for the wind technology. In this case, over $13 million of credits are lost because of the lack of offsetting taxes. In addition, $15 million in taxes on operating losses from the early years are lost. They cannot be used to offset positive taxes before the 15-year time limit is over. The net effect is a decline in the wind IRR from 6.5% to 1.5%. With the AMT in effect as well as carryforward, the IRR stays the same as with carry-forward alone. Net federal taxes remain zero in both cases. With the AMT there are fewer tax credits from operating losses that get lost because they are not used within 15 years. Instead of $15 million in credits lost, only $3 million are lost.

7. DETERMINING RELATIVE BARRIERS AND INCENTIVES

In Sections 2 through 6, we laid the foundation for answering questions posed by Section 1205 of the Energy Policy Act of 1992 (EPACT) by (1) quantifying basic financial and technical parameters of seven renewable and four conventional electric generating technologies, (2) identifying applicable tax measures and ratemaking procedures for investor-owned utilities (IOUs) and nonutility generators (NUGs), and (3) simulating the effects of changing these measures and procedures on the financial criteria used by IOUs and NUGs for making generation resource decisions. The results of the simulations identify tax and ratemaking barriers and incentives for individual technologies. In this section, we take the analysis one step further by determining whether the barriers and incentives defined in Sections 5 and 6 for renewable technologies are significantly greater than for conventional ones. Or, in the words of Section 1205 of EPACT, we determine "if conventional taxation and ratemaking procedures result in economic barriers to or incentives for renewable energy power plants *compared to* conventional power plants." (Emphasis supplied.)

Before proceeding to a discussion of the results of that comparison, however, in Sections 7.1 and 7.2 we place this study in the context of power-plant decisionmaking by addressing factors other than financial attractiveness that affect decisions on technology adoption by IOUs and NUGs. Three factors are especially important. First, we discuss the influence of integrated resource planning (IRP) on an IOU's technology-adoption decisions. Second, we discuss technical and financial risk, risk-bearers, and the influence of risk on decisionmaking. Finally, we mention public policies toward renewable and conventional generating technologies, which may encourage the use of certain technologies by reducing their technical and/or financial risk. We present a qualitative discussion of these three factors because it is not possible to quantify their effects on technology adoption even though they are crucial in the decisionmaking process. Although the relative tax and ratemaking barriers and incentives presented in Section 7.3 are part of the financial determination of technology adoption, there are other important considerations that also shape decisionmaking on electric generating technology adoption.

7.1. INTEGRATED RESOURCE PLANNING AND RESOURCE SELECTION

The results of this study only indicate directions of financial attractiveness: barriers to--and incentives for--adopting renewable and conventional power plants. The results do not suggest which technologies will be adopted by IOUs or NUGs. In real-world settings, technologies are only cost (in)effective relative to a given power system. Technical factors such as availability, diversity, dispatchability, and reliability are also integral parts of the decisionmaking process, as are the technical and financial characteristics of competing supply and demand resource options.

Expanding on the latter point, many IOUs are looking to reduce demand as a way to meet energy and load requirements. That is, changing the pattern and level of electricity demand (i.e., demand-side management (DSM)) with conservation and load management strategies is considered a resource option along with traditional supply resources (e.g., building new generating stations, extending the life of old ones, or

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purchasing power from other sources). The process of selecting a resource mix on basis of comparing the benefits and costs of all demand and supply options is refer to as IRP. The IRP process is an integration of (1) traditional least-cost plannin process by which utilities minimize the cost of generating a given amount of electric (2) demand-side planning, and (3) other relevant factors. IRP gives the electric ut more options to consider in developing its resource strategy.

In this study, we did not model this complex decisionmaking process which va from state to state and utility to utility. Rather, we estimated the relative impact of cert tax measures and ratemaking procedures on financial criteria that IOUs and NUGs u as inputs to make technology-adoption decisions. Where these tax measures a ratemaking procedures provide incentives for an alternative, however, they increase t likelihood that the alternative will be selected by IOUs or NUGs when making generati resource decisions.

7.2. RISK, PUBLIC POLICY, AND RESOURCE SELECTION

The seven renewable and four conventional technologies considered in this stu share common characteristics. They each require capital, labor, energy, and materi for their construction and also require, to varying degrees, labor, energy, and materi for their operation. From these shared characteristics, the technologies diverge marke in technical and financial characteristics and public policy treatment. In this study, we not provide a taxonomy of all of these technical/financial and policy differences for the technologies. In the following paragraphs, however, we will identify important differenc and identify how they influence the decisionmaking process.

Given the differences in technical and financial characteristics of the 11 generati technologies considered in this study, it follows that there are differences in technical a financial risks associated with using the technologies. An important factor taken in consideration by IOUs and NUGs when making technology-adoption decisions is t allocation of these risks among affected parties.

One important consideration in adopting a generating technology is the risk th the technology will not be able to perform its assigned work load in a power delive system because of operating constraints. As an example, hydroelectric plants requi substantial amounts of rain or snow annually. For hydroelectric plants, an importa consideration is the party bearing the financial risk of providing power from alternati sources in the event of a drought. If redundant capacity must be constructed to hed against a drought or power must be purchased to replace a hydro shortfall, the party th is expected to bear the increased cost has higher risk. If rainfall is larger than expect and there is a surplus of hydropower, the party bearing the risk may experience windfall.

A further distinction in the financial risk of adopting renewable versus convention technologies concerns the capital and fuel intensity of generating technologies. evaluating technologies, analysts necessarily project future capital and operating cos There will be a bias for or against adopting a generating technology depending on t party bearing the risk that costs may differ from projections made at the time that t technology is selected. For example, a fossil fuel-intensive technology is more attractive to a decisionmaker if the decisionmaker does not bear the risk of fuel-price fluctuations. Therefore, the ratemaking procedure of passing through the risk of fuel-price fluctuations to ratepayers favors fuel-consuming technologies. This is a barrier to the adoption of renewable technologies that are not subject to fuel-price fluctuations.

A similar argument can be made for construction costs that differ from those projected at the time that the technology-adoption decision is made. If the out-of-pocket construction costs of a generating plant are greater than forecasted, who bears the cost? If construction costs are less than projected, who reaps the benefits?

The distribution of these risks among parties is typically determined by regulatory authorities in the ratemaking process. For example, fuel costs higher than expected at the time of technology-adoption decisions are typically borne by ratepayers. The benefits of fuel costs less than expected are also typically reaped by ratepayers. Construction costs are typically subject to prudence reviews. If actual construction costs exceed projected amounts by a large margin, some regulatory authorities have required cost-sharing--i.e., ratepayers bear part of the excess cost along with investors. The benefits of construction costs less than projected are typically reaped by ratepayers.

Like the IRP paradigm discussed in the previous section, these technical and financial risks--and the parties bearing them--are important considerations for decisionmakers when making technology-adoption choices. However, it is extremely difficult to quantify the effects that these risks have on technology choices in terms of the financial criteria that we used. We made no attempt to do so in this study.

Although historical and current policy measures that affect development and adoption of electric generating technologies are beyond the scope of Section 1205 of EPACT, for completeness we mention some of these measures below.

Publicly owned utilities (POUs) were excluded from this study because they are not subject to federal taxes and ratemaking procedures in the same manner as IOUs. POUs may have a bias for capital-intensive technologies (such as renewable ones) because of capital subsidies available to them. Also, current and historical subsidies for some electric-generating fuels make technologies that use these fuels more attractive than they otherwise would be in the absence of those subsidies. By not analyzing entire fuel cycles, we do not capture the potential bias for these fuel-intensive technologies. Similarly, we did not address current and historical public R&D subsidies for development of energy technologies, including both renewable and conventional electric generating technologies.

In this study, we examined a particular set of tax measures and ratemaking procedures as prescribed by Section 1205 of EPACT. These measures and procedures provide barriers and incentives to technology adoption and their appropriateness should be examined closely by federal and state regulatory authorities. Further study is required to examine the barriers and incentives for technology adoption beyond those considered in this study and discussed in the next section.

7.3. RATEMAKING AND TAXATION BARRIERS AND INCENTIVES

In this study, we estimated the differential effects of current tax measures a ratemaking procedures on the financial criteria that IOUs and NUGs use to ma decisions on adopting electric generating technologies. The purpose of estimating the effects is to determine whether the taxation and ratemaking procedures result in barri to or incentives for the adoption of renewable generating technologies compared conventional ones. For IOUs, the technology's levelized cost is the primary criterion. F NUGs, the primary criterion is the internal rate of return (IRR).

Because the enabling legislation for this study (Section 1205 of EPACT) limits scope to decisions on renewable vs. conventional generating plants, no attempt w made to examine tax policies outside of those that apply to decisions on generati plants.[1]

In Sections 5 and 6, taxation and ratemaking 'barriers' to and 'incentives' t adopting technologies are defined in terms of their effects on values of t decisionmaking criteria. For example, using the primary financial criterion for IOUs, i tax measure or ratemaking procedure results in a lower levelized cost for any of t technologies measured from the reference case, the procedure is an incentive t adopting the technology. Conversely, if the levelized cost is higher, the procedure is barrier. Likewise for NUGs, if a tax measure[2] results in a higher IRR, the tax is incentive for adopting the technology. If the return is lower, it is a barrier to adoption

However, Section 1205 of EPACT requires more than just determining whether not a measure or procedure is a barrier or incentive. It specifically states a determinati must be made as to whether the measures and procedures are barriers and incentiv "for renewable energy power plants compared to conventional power plants." Therefo in the following tables we compare the effects of the tax measures and ratemaki procedures on renewable technologies to the effects on conventional ones. If t measure or procedure benefits a renewable technology more than conventior technologies, it is an incentive (I) for the renewable technology. Conversely, if t measure or procedure benefits conventional technologies more than the renewab technology, it is a barrier (B) to the renewable technology. We use information fro Sections 5 and 6 to make this determination.

We summarize the results on barriers (Bs) to and incentives (Is) for adoption each of the renewable technologies under all tax measures and ratemaking procedur considered in this study for IOUs in Table 7.1. We provide similar results for NUGs Table 7.2. Differences in the two tables reflect the fact that NUGs are more likely to l subject to the alternative minimum tax (AMT) than IOUs and they are not subject to th

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[1]For the interested reader, however, Section 3015 of EPACT requires the National Academy Sciences to conduct a broader study on energy subsidies which presumably will address tax policies ot than those affecting decisions on technology-adoption.

[2]Note that ratemaking procedures do not apply to NUGs.

Table 7.1
Barriers To and Incentives For Renewable Technologies
Comparison With Conventional Technologies
Investor-Owned Utilities

Measure/ Procedure	Biomass Plantation	Biomass Waste	Geothermal	Hydro	Solar PV	Solar Thermal	Wind
Taxation Effects:							
All Taxes	I	-	-	B	B	-	I
Local Property Taxes	-	-	-	B	B	B	B
Taxes on Inputs	-	-	-	-	-	-	-
State Income Taxes	-	-	-	-	-	-	-
Federal Income Taxes[a]	I	-	I	-	I	I	I
Accelerated Depreciation[b]	-	-	I	I	I	I	I
Federal Tax Credits[c]	I	NA	NA	NA	NA	NA	I
Ratemaking Effects:							
No CWIP in the Rate Base	-	-	-	-	-	-	-
Tax Normalization	-	-	-	I	I	I	I
Fuel Adjustment Clauses	-	-	-	-	-	-	-

SOURCES: Tables C.1 and C.2 in Appendix C.

A 'B' indicates that the tax measure or ratemaking procedure is a barrier to adopting the technology based on comparing the ratio of the measure's or procedure's effect with the average value of the ratios of conventional technologies. If the value of the ratio is more than five percent greater than the corresponding average value for conventional technologies, the measure or procedure is a barrier.

An 'I' indicates that the tax measure or ratemaking procedure is an incentive to adopting the technology based on comparing the ratio of the measure's or procedure's effect with the average value of the ratios of conventional technologies. If the value of the ratio is more than five percent less than the corresponding average value for conventional technologies, the measure or procedure is an incentive.

An 'NA' indicates that the measure is not applicable to the technology.

An '-' indicates that the measure or procedure is applicable, but the value of the ratio is within ± five percent of the average for conventional technologies.

[a]Includes the effects of all federal income taxes, including accelerated depreciation, and federal production and investment tax credits.

[b]Includes the effects of accelerated depreciation exclusively.

[c]Includes the effects of federal production and investment tax credits exclusively.

Table 7.2
Barriers To and Incentives For Renewable Technologies
Comparison With Conventional Technologies
Nonutility Generators

Measure/ Procedure	Biomass Plantation	Biomass Waste	Geothermal	Hydro	Solar PV	Solar Thermal	W
All Taxes	I	I	I	I	I	I	
Local Property Taxes	-	-	-	-	-	-	
Taxes on Inputs	-	-	-	I	I	I	
State Income Taxes	I	-	-	-	-	-	
Federal Income Taxes[a]	I	I	I	I	I	I	
Accelerated Depreciation[b]	I	I	I	-	I	I	
Federal Tax Credits[c]	I	NA	I	NA	I	I	
Alternative Minimum Tax[d]	B	B	B	B	B	B	

SOURCE: Table C.3 in Appendix C.

A 'B' indicates that the tax measure is a barrier to adopting the technology based on comparing the rati the measure's effect with the average value of the ratios of conventional technologies. If the value of the is more than five percent less than the corresponding average value for conventional technologies, measure a barrier.

An 'I' indicates that the tax measure is an incentive to adopting the technology based on comparing the of the measure's effect with the average value of the ratios of conventional technologies. If the value o ratio is more than five percent greater than the corresponding average value for conventional technolog the measure is an incentive.

An 'NA' indicates that the measure is not applicable to the technology.

An '-' indicates that the measure is applicable, but the value of the ratio is within ± five percent of the ave for conventional technologies.

[a]Includes the effects of all federal income taxes, including accelerated depreciation, and federal produc and investment tax credits.

[b]Includes the effects of accelerated depreciation exclusively.

[c]Includes the effects of federal production and investment tax credits exclusively.

[d]Includes the effects of the alternative minimum tax.

same ratemaking procedures as IOUs.

As the notes to the tables indicate, a tax measure or ratemaking procedure renewable technologies was determined to be a barrier or incentive to renewable technology adoption compared with conventional technologies if the financial ratios presented in Sections 5 and 6 differ by more than five percent points from the average of the four conventional technologies. The applicable values presented in Sections 5 and 6 are the ratios of the values of the financial indicators without the measure or procedure included to the values of the financial indicators with the measures or procedures. The five percentage point difference from the average values of the conventional technologies is presumed to be large enough to change the relative financial attractiveness of different technologies.[3]

From Table 7.1, taxes for IOUs at the state, local, and federal levels (i.e., 'all taxes') are incentives for two of the seven renewable technologies, and a barrier for hydro and solar PV. For NUGs (Table 7.2), 'all taxes' are incentives for all seven renewable technologies compared to conventional technologies. The primary reasons for these conclusions are the large financial benefits provided by accelerated depreciation and the production and investment tax credits, which do not apply to conventional technologies.

For IOUs, property taxes are barriers to the adoption of hydro, solar and wind technologies, compared to conventional technologies. For NUGs, property taxes are only a barrier to the adoption of wind. The reason is the higher capital intensity of the affected renewable technologies in comparison with conventional ones. As shown in Sections 5 and 6, this conclusion is robust under different assumptions about the bases used to calculate property taxes.

Taxes on inputs are incentives for the hydro and solar technologies adopted by NUGs, but they are neither incentives nor barriers for adoption by IOUs. Similarly, state income taxes are an incentive for biomass-plantation and wind technologies if adopted by NUGs, but are neither barriers nor incentives if adopted by IOUs.

Holding effects of the AMT aside for the moment, certain provisions of federal income tax laws provide more incentives for adopting renewable technologies than conventional ones by both IOUs and NUGs. First, as indicated by the analysis in Sections 5 and 6, although accelerated depreciation benefits all renewable and conventional technologies, it is more of an incentive for many of the renewable technologies. This is especially true because of the very short tax depreciation lives of solar, wind, hydro, and geothermal technologies adopted by IOUs and solar, wind, geothermal, and biomass plants adopted by NUGs. Second, provisions of EPACT extending the investment tax credit for solar and geothermal technologies that are adopted by NUGs and providing a 1.5¢/kWh production incentive credit for dedicated-plantation biomass and wind technologies adopted by both IOUs and NUGs are especially attractive financial incentives for the affected ownership types.

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[3]Because the financial indicator for NUGs is expressed as a percentage, an alternative method was also used to calculate relative barriers and incentives for NUGs. The alternative is based on differences in percentages--rather than differences in ratios. The results of using this alternative method do not change conclusions substantially on barriers and incentives. These results are contained in Table C.4 of Appendix C.

If a NUG is subject to the AMT, however, the NUG is not able to take advant of the federal tax incentives for renewables and, therefore, the federal tax laws bec a barrier to the adoption of renewable technologies compared with conventional o Dedicated-plantation biomass and wind technologies are especially harmed by the / because the 1.5¢/kWh credit cannot be used.

As Table 7.1 indicates, of the ratemaking procedures that we modeled, the (one that provides a barrier or incentive to the adoption of renewable technologies is normalization. It is an incentive for the adoption of hydro, solar, and wind technolog

If we were able to quantify the effects of the ratemaking procedure that pas the risk of fuel-price fluctuations to ratepayers, the results would show that this procec is a barrier to the adoption of renewable technologies that are not subject to fuel-p fluctuations.

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APPENDIX A: DESCRIPTION OF THE MODEL

A.1. BACKGROUND

In this appendix, we discuss technical features of the financial regulatory model used in this study. The specification of the model is an extension of one provided the authors by Dona Burney of the District of Columbia Public Service Commission. Because the changes are substantial, however, the authors accept full responsibility for the current specification.

As discussed in the text, financial simulations were executed for the decision-making criteria of both IOUs and NUGs. Therefore, the discussion in this appendix is divided into two parts, addressing, first, electric utilities and then NUGs. Because many financial issues pertaining to NUGs are similar to or the same as those of IOUs, the discussion of NUGs will be abbreviated.

The computer model used to analyze the various tax and ratemaking procedures is based on a spreadsheet that calculates the contribution of a single power plant to a utility's financial performance. It includes such factors as the capital outlays, debt requirements, fuel costs, O&M costs, depreciation, taxes, rate base, and return to equity holders. The model develops full financial statements for the plant for each year from the beginning of construction to final shutdown. A variation of the model uses a fixed input price instead of a rate base calculation for pricing in order to model an NUG.

Because the model considers only the construction of a single plant, it does not have to deal with issues such as demand growth, retirement of existing capacity, and the type of plant needed. We assumed for the purpose of this study that the utility had decided that the technology being modeled matched its needs in the way of capacity and timing. Generation is based solely on the input capacity times the input capacity factor. This reduces the complexity of the analysis to allow us to focus on the tax and ratemaking procedures as they affect each technology.

The costs of a single plant affect the parent utility through increases or decreases in the balance sheet and earnings statement. This will affect the taxes to be paid, the rate base on which the utility can collect, and the consequent cash flow. This study look at the effects of a technology at the margin for a utility and does not look at a hypothetical utility in its entirety.

A.2. INVESTOR-OWNED ELECTRIC UTILITIES (IOUs)

A.2.1. Overview

In Fig. A.1, we summarize how the financial regulatory model calculates required revenues for IOUs. The levelized cost is simply the discounted value of the required revenues by the annual electricity generation.

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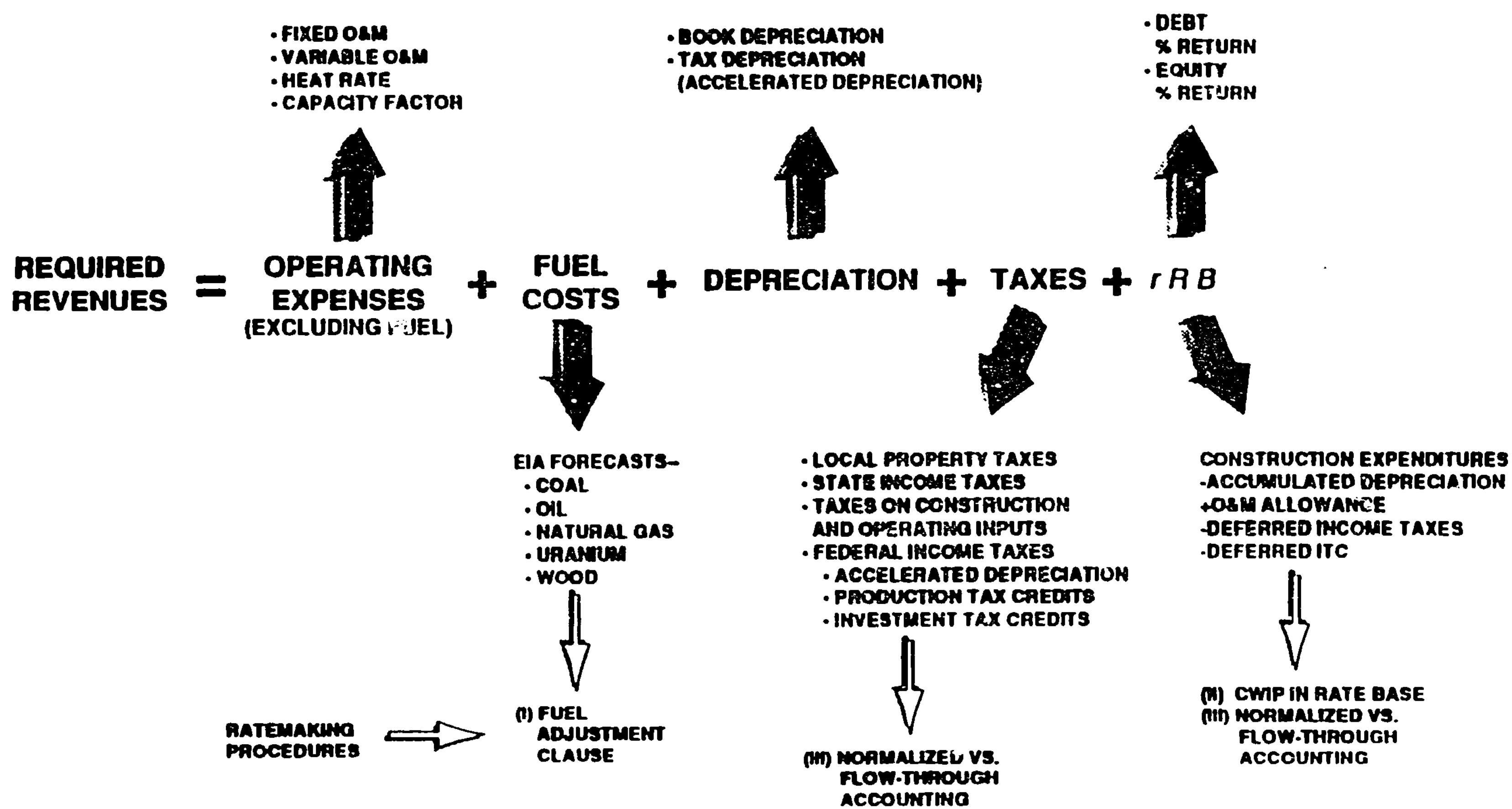
FIGURE A.1

RATEMAKING FORMULA FOR INVESTOR-OWNED UTILITIES



A.2.2. Components of Required Revenues

A.2.2.1. Fuel Costs

The 1991 cost of fossil fuels and their projected values over the useful lives of the plants considered in the study (in 1991 dollars) were obtained from the Energy Information Administration.

Fuel costs are calculated on the basis of plant production and capacity and escalated if necessary. Because taxes on fuel are calculated later in the model, the input fuel cost is multiplied by the input percentage of the fuel cost not attributed to sales tax. The equation is

$$\text{Fuel Cost per kWh} = \text{Input Fuel Cost per kWh} \times \text{Fuel Cost \% without Tax.}$$

This fuel cost is then converted to thousands of dollars by multiplying by the production rate for each year and escalated based on the basis of the input escalation rate:

$$\text{Fuel Cost}_t = \text{Fuel Cost \$ per MWh} \times \text{Capacity} \times \text{Capacity Factor} \times 8760 \text{ hours} \times (1 + \text{Fuel Escalation})^{t-t_0} \times (\text{K\$}/1000\$)$$

where t = year of outlay and t_0 = first year.

To model the lack of an automatic fuel adjustment clause (one of the sensitivities studied), the fuel costs in the required revenue calculation increase at only the O&M escalation rate (our stand-in for the general inflation rate) instead of the fuel escalation rate for the next year. If the fuel escalation rate is higher, then not all fuel costs are recovered that year. The shortfall is then recovered the following year. However, that next year has a similar shortfall for its year's fuel cost based on the differential escalation rates. The equation is:

$$\text{Fuel Cost Recovered}_t = [\text{Fuel Cost}_t \times (1 + \text{O\&M Escalation})/(1 + \text{Fuel Escalation})] + (\text{Fuel Cost using fuel escalation}_{t-1} - \text{Fuel Cost using O\&M escalation}_{t-1})$$

The result is that the revenue in the first year of plant operation has a fairly significant shortfall based on the difference in escalation rates, and the revenue for all future years have a very minor difference because they include the previous year's shortfall. Finally, in the year after shutdown, the missing fuel costs are recovered.

A.2.2.2. Other O&M Expenses

O&M expenses other than fuel include labor and materials used in operation, plant maintenance, waste disposal, and site management. For some technologies, such as geothermal and nuclear, these costs are a significant fraction of the overall costs. The costs may be entered into the model as a fixed cost per kilowatt of capacity or as a cost per kilowatt-hour produced. The costs are split between labor, material, and taxes on labor and material. The user inputs the appropriate percentages of the total that represent the labor and material costs without taxes. Later in the model, these costs will be multiplied by the appropriate input tax rate to find the tax components of the O&M costs. The equations are

O&M Labor Cost = Input O&M Cost x Labor Cost % without Tax
O&M Material Cost = Input O&M Cost x Material Cost % without Tax.

These are converted to thousands of dollars and escalated using the input O&M escalation rate:

$$\begin{aligned} \text{O\&M Cost}_t = {} & [\text{O\&M \$ per MWh} \times \text{Capacity} \times \text{Capacity Factor} \times 8760 \text{ hours} \\ & + \text{O\&M \$ per kW} \times \text{Capacity} \times (1000\text{kW/MW})] \\ & \times (1 + \text{Fuel Escalation})^{t-t0} \times (\text{K\$/1000\$}). \end{aligned}$$

A.2.2.3. Depreciation

Before depreciation is calculated, the total capital cost of the plant must be found. The input contains the total capital cost of the plant in dollars per kilowatt. This cost is the overnight construction cost. In other words, it is the cost in constant dollars without interest or inflation due to the length of time it takes to build the plant. These two factors are calculated separately within the model. The input includes a schedule showing what fraction of the plant is built in which year before the plant comes on-line. These fractions are based on constant dollars and total to 100%. The capital outlays in a given year are equal to the total capital cost times the fraction of total cost for the appropriate year before start-up times the escalation factor for construction costs.

$$\begin{aligned} \text{Capital Outlay}_t = {} & \text{Capital Cost} \times \text{Fraction of Total}_{t-ts} \\ & \times (1 + \text{Construction Escalation Rate})^{t-t0} \end{aligned}$$

where ts = year of startup.

The input to the model also includes the percentages of the capital cost that are attributable to labor, material, energy, and land. These percentages do not include the taxes on each of these components; the taxes on these inputs are calculated separately. The capital outlay is multiplied by each one of the components' fractions to find their representative cost. The cost for each is then multiplied by the appropriate tax rate to find the taxes on that input to the capital cost. The sum of all components and their taxes total to 100% of the capital outlay for the year:

$$\text{Component Cost}_{it} = \text{Capital Outlay}_t \times \text{Component Cost \% w/o Tax}$$
$$\text{Component Tax}_{it} = \text{Component Cost}_{it} \times \text{Tax Rate}_i$$

$$\Sigma_i \text{ Component Cost}_{it} + \text{Component Tax}_{it} = 100\% \text{ of Capital Outlay},$$

where i = Cost Category (Labor, Energy, Material, Land).

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As capital outlays are made, they are added into an asset account called Construction Work in Progress (CWIP). In the year the plant begins operation, the cost is transferred to Gross Plant & Equipment (Gross P&E). Except for the cost of the land, these costs are depreciated as described below. The land value, on the other hand, is held on the books at cost. In the last year of operation, the land is simulated to be sold at cost. Since revenue and cost offset each other, this transaction has no effect on the required revenue calculation or the income statement. The sale of the land does, however, increase equity cash flow in the final year. This land value can be thought of as the salvage value of the facility at the end of its life.

A separate asset which must be depreciated, if it exists, is the Allowance for Funds used During Construction (AFUDC). It represents the amount of return that the utility would have earned on the CWIP if it had charged customers the allowed rate of return on assets before operation. The AFUDC accumulates during the construction phase and enters the ratebase when the plant begins operation. It then is depreciated over the life of the plant using straight line depreciation just as the rest of the P&E (see below). The model separates the components of AFUDC between allowance for borrowed funds (AFBF) and equity funds (AFEF). The equations are

$$\text{AFBF} = (\text{CWIP} + \text{cumulative AFUDC})_{\text{BOY}} \times \text{Debt Ratio} \times \text{Interest Rate}$$

$$\text{AFEF} = (\text{CWIP} + \text{cumulative AFUDC})_{\text{BOY}} \times (1 - \text{Debt Ratio}) \times \text{Allowed Return on Equity}$$

$$\text{Annual AFUDC} = \text{AFBF} + \text{AFEF},$$

where BOY = Beginning of year.

The AFUDC enters the income statement as a quasi-revenue but is not a real cash inflow. Instead, it is collected from customers over the life of the plant through its depreciation and the earned return on the undepreciated portion. If the user chooses to allow CWIP in the ratebase, AFUDC does not exist because the utility is truly recovering the funds during construction.

Book depreciation is now calculated so that it may be collected in the required revenue. As mentioned above, this includes all the capitalized costs except land, i.e., labor, material, energy, and taxes on the four components. In addition, the AFUDC is depreciated over the life of the plant and collected in revenues.

$$\text{Annual Book Depreciation} = (\text{Gross Plant \& Equipment (including AFUDC)} - \text{Land}) \,/\, \text{Plant Life}$$

Tax depreciation is calculated using a double-declining balance method if the tax life is less than 15 years and a one-and-a-half declining balance for tax lives of 15 years or greater. Tax calculations do not include AFUDC. The equation is

Depreciation Using Double = [Gross P&E (w/o AFUDC) - Land -Accumulated
Declining Balance Tax Depreciation] x 2 / Tax Depreciation Life

Note: One-and-a-half declining balance would use 1.5 instead of 2 in the equation.

The tax code requires that the calculation assume that the plant starts in the middle of the first year of operation for tax depreciation. For example, a plant with a 5-year tax life would have depreciation of 20% of its value in the first year. In the second year, the amount would be 32% (40% of the remaining 80%.) The third year would be 19.2% (40% of the remaining 48%.)

Because the double-declining balance equation never fully depreciates an asset, the amount of depreciation using straight line depreciation is also calculated. This straight-line calculation, however, only uses the net value of the plant and the years remaining in the tax life of the plant. Towards the end of the tax life, the straight-line value is higher than the double declining balance value. Once it becomes higher, this straight-line depreciation is used instead.

Annual Tax Depreciation = MAXIMUM [Double-Declining-Balance method, (Gross P&E (w/o AFUDC) - Land - Accumulated Tax Depreciation)/ Years Remaining in Tax Life].

To continue the example, in the fourth year the double-declining balance method sets the depreciation at 11.52%. The straight-line depreciation of the remaining 28.8% of the asset over two and a half years is also 11.52%. In the fifth year the double-declining balance equation gives only 6.9%; the straight-line value of 11.52% is used again. In year 6, the final 5.76% is depreciated.

A.2.2.4. Taxes

There are a variety of taxes included in the model. All taxes are included in the required revenue calculation at some point in time. Expensed taxes are those that are not capitalized in the plant. They are recovered in the year of their expense. Capitalized taxes are those that were part of the construction costs and are built into the capital costs. They are expensed as part of the depreciation cost of the plant. Property taxes are paid on the basis of assessed values and an input rate. The income tax calculation includes both the current taxes payable and the annual deferred taxes that are due to accelerated depreciation. Any available tax credits reduce the current taxes and consequently lower the required revenues.

Taxes on the inputs to production are charged on the fuel, labor, materials, and land costs for each year. These are found by multiplying the appropriate cost category by the input tax rate:

$$\text{Input Taxes on Costs}_{it} = \text{Cost}_{it} \times \text{Tax Rate}_{i,}$$

where i = Cost Category (Labor, Energy, Material, Land), and t = year.

Those taxes on cost components of the capital outlays for the plant are incorporated into the CWIP and thence into the P&E. The taxes are then depreciated over time along with the rest of the plant. Taxes on the inputs to production that are expensed in the same year (i.e., O&M labor, O&M materials, fuel) appear on the income statement and in the revenue requirement calculation in the same year as the expense.

The model has the capability to calculate a tax on the kilowatt-hour output of the plant. This was used in early versions of the model to analyze the proposed BTU tax, but was not used in the results of the final report.

Property taxes are calculated by multiplying the assessed value of the plant by the input tax rate. There are several methods within the model for simulating the assessed value. The net book value is used in the reference scenarios in the absence of a known market value. The input tax rate should be adjusted beforehand to take into account that many states assess property at a fraction of its full value.

Property Tax = Assessed Value x Property Tax Rate,

where Assessed Value = Net Book Value of Plant, or
Gross Book Value of Plant, or
Net Present Value of remaining Cash Flow to Equity, or
Net Book Value of Plant less Land Value.

The model calculates income taxes by developing an income statement that uses accelerated depreciation instead of book depreciation and does not include any allowance for funds used during construction. Pre-tax income is calculated by subtracting fuel, O&M, accelerated depreciation, and interest from the required revenue amount.

Pre-Tax Income = Revenue - Fuel - O&M Cost - Accelerated Depreciation - Interest

From this amount is subtracted the expensed taxes on inputs, property taxes, and production taxes. This amount is multiplied by the state income tax rate to determine the state income taxes. The equation is

Current State Income Taxes = (Pre-Tax Income - Input Taxes -Property Taxes - Production Taxes) x State Income Tax Rate

The current federal income taxes payable are found similarly, but since state taxes are tax-deductible, state income taxes are included in the equation.

Current Federal Income Taxes = (Pre-Tax Income - Input Taxes -Property Taxes - Production Taxes - Current State Income Taxes) x Federal Income Tax Rate

Because the required revenue calculation includes the income taxes, which in turn require the revenue amount, iteration would normally be required. However, the equations for the income taxes can be reformulated to eliminate the recursiveness. Doing this greatly speeds the calculation.

Annual deferred taxes are those taxes which will eventually be paid but are not due yet because of accelerated depreciation. They are found by taking the difference between the two forms of depreciation and multiplying by the state and federal income tax rate. Since tax calculations do not use AFUDC, the book depreciation has this component removed. The equation is

Annual Deferred Taxes = (Tax Depreciation - Book Depreciation (w/o AFUDC)) x (State Income Tax Rate + Federal Income Tax Rate).

In the early years, deferred taxes will be positive because of the high accelerated depreciation. Once the plant is past its tax life, the annual deferred taxes will be negative. The deferred taxes are accumulated and treated as a liability on the balance sheet because they must eventually be paid. As they are paid (negative annual deferred taxes) the cumulative amount declines to zero at the end of the book life of the plant.

If taxes are normalized, the deferred taxes are collected from ratepayers in the revenue calculation. This raises the revenue requirement in the early years and lowers it in the later years. However, the accumulated deferred taxes are subtracted from the asset value in the rate base calculation. Customers should not have to pay the taxes early (by paying deferred taxes) as well as pay a return to the utility on those funds until they are paid to the government. If taxes are not normalized, then the revenue calculation would include only current taxes and not deferred taxes.

The investment tax credit is found by multiplying the gross P&E by the input tax credit rate. It applies only in the first year of operation.

Investment Tax Credit = Gross P&E (w/o AFUDC) x ITC Rate.

The production tax credit calculation is more complicated. The EPACT establishes a 1.5¢/kWh tax credit for wind and closed-loop biomass projects. However, it applies in full only if the price of electricity from the plant is at or below 8¢/kWh. Between 8¢ and 11¢, the credit decreases linearly to zero. At prices over 11¢/kWh, no credit applies. The equation used is

Production Tax Credit = 1.5¢/kWh x MINIMUM[1.0, MAXIMUM((11¢/kWh–Price) / 3, 0.0)] x Production

A price is not specifically used for sales of electricity from the plant if it is modeled as utility-owned. Instead, an effective price is calculated by dividing the calculated required revenue by the production amount. Since the effective price requires the required revenue which requires the credit amount, a recursive formula and iteration must be used.

Also, the credit is available only during the first 10 years of plant operation. Inflation factors can be applied to the 1.5¢ and 8¢ figures.

Because the investment and production tax credits are not taxable, their impact is amplified. For example, the production tax credit lowers required revenues by 1.5¢/kWh. Lowered revenues lower the federal income taxes by 35% of the credit; this decrease, in turn, lowers required revenues further. The result is that the effective price is lowered 2.27¢/kWh, an amplification of over 50%. A similar effect occurs with state income taxes.

A.2.2.5. Return on Rate Base

The return on rate base is equal to the rate base at the beginning of the year multiplied by an allowable percentage return based on the cost of capital. The rate base equation is

Total Rate Base = Net P&E + CWIP Allowed in Rate Base
+ Capitalized AFUDC + Working Capital
- Capitalized Deferred Taxes.

The working capital is defined as an input fraction of the next year's O&M cost (we used 12.5%). This is used to represent that the utility needs about 1.5 months of the operating costs in reserves. The other components of the rate base were discussed in previous sections.

In the years before operation, the only non-zero component of the rate base is the CWIP allowed. If no CWIP is allowed, the rate base is zero until the plant comes on-line. Except under this circumstance, the rate base is also equal to the sum of the debt and equity investment. It is not equal to total assets because the deferred taxes liability does not earn a return, since the customers have already paid this through normalization of taxes.

The allowable percentage return on investment is the weighted average cost of debt and equity capital before taxes. Since deferred taxes, which earn no return, are subtracted out of the rate base, the percentage return must be modified to reflect this. Therefore, the total return on rate base is equal to

$$\text{Allowed \% Return} = \text{Allowed Equity Rate of Return} \times (\text{Equity}_{BOY} / \text{Rate Base}) + \text{Interest Rate} \times (\text{Debt}_{BOY} / \text{Rate Base})$$

This equation does not use after-tax cost of capital because it is used to calculate total revenues before taxes. The return on rate base is then equal to the total rate base times the allowed return. It also equals the interest charge for the year plus the equity investment times its allowed rate of return. The equations are

Return on Rate Base = Total Rate Base x Allowed % Return, or

Return on Rate Base = Interest Charge + Allowed Return on Equity.

New debt is issued each year on the basis of multiplying the sum of capital outlays, AFUDC, and working capital requirements by the input debt ratio:

$$\text{Debt Issued}_t = (\text{Capital Outlays}_t + \text{AFUDC}_t + \text{Change in Working Capital}_t).$$

Interest is charged on the amount of debt held at the beginning of the year. (To ease calculations throughout the modeling, we assumed that all transactions are carried out at year-end and that the plant begins operation at the beginning of a year.)

Debt is retired at the same rate that the capital investment is depreciated using book depreciation. Although this may not be the same schedule that actual utilities use, it maintains a constant debt ratio over the life of the investment and avoids perturbations based on bond lengths versus plant lives. Since this model simulates only one power plant instead of the utility's entire asset base, this assumption is a reasonable simplification.

A.2.3. Decisionmaking Criteria

Marginal income statements and balance sheets reflecting the financial effects of each of the technologies are calculated for each year. These can be used to calculate financial ratios familiar to investment analysts. The results are also important for use in the calculation of the next year's costs and revenue requirements.

A.2.3.1. Levelized Cost

The levelized cost to customers equals the net present value (NPV) of the annual revenue from electricity sales as calculated using the rate base formula divided by the NPV of the kilowatt-hours produced. (Our model considers only busbar costs and does not include transmission losses of electricity.)The net present value of the revenue required is the sum of the revenues over the life of the plant, with each year's revenues discounted by the cost of capital to the present.

$$\text{NPV(Revenues)} = \Sigma_t \text{ Revenues}_t \times (1 + \text{discount rate})^{t-t0}$$

where Revenues = calculated revenues required from rate base calculation.

The equation uses the weighted average cost of capital to the utility after taxes for the discount rate. It is based on the allowed return on equity and the after-tax cost of debt, weighted by the percentage of each form of investment used during construction.

Cost of Capital =Allowed Equity Rate of Return x (1 - Debt Ratio) + Interest Rate x Debt Ratio x (1 - Federal Income Tax Rate - State Income Tax Rate + Federal Income Tax Rate + State Income Tax Rate).

In scenarios with no income tax, the equation uses the reference scenario tax rates to provide a more consistent comparison.

The NPV of kilowatt-hours produced is used to find the levelized price through the following equations. We want to find a single price which, when multiplied by the kilowatt-hours produced each year, gives the same NPV of revenues as the actual stream of revenues.

NPV (Revenues) = NPV (Levelized Price x kWh produced).

Since the levelized price is a constant, it can be pulled out of the NPV equation:

NPV (Revenues) = Levelized Price x NPV (kWh produced).

The levelized price can then be found by rearranging the equation:

Levelized Price = NPV (Revenues) / NPV (kWh produced).

The levelized price can also be thought of as the levelized cost to customers. In this study we use the terms interchangeably.

The revenue can be segmented on the basis of the various types of costs used to calculate it. We have combined these into seven major groupings for the tables in Appendix B. These are: capital costs, O&M costs, fuel costs, federal taxes, state and local taxes, property taxes, and tax credits.

A.2.3.2. Internal Rate of Return

The cash flow to the debt and equity holders combined is the basis for calculating the internal rate of return. This defines the cash flow of the project as a whole, without regard to the financial arrangements in its financing. It can be found through components of the income statement and balance sheet or through a bottoms-up summation of cash inflows and outflows.

Cash Flow = Cash Revenues - Capital Outlays - Fuel Costs - O&M Costs - Change in Working Capital - Taxes,

or

Cash Flow = Net Income + Depreciation + AFUDC Depreciation + Deferred Taxes + Interest - Capital Outlays -AFUDC.

The internal rate of return (IRR) is the discount rate that causes the NPV of the net cash flow over the entire period to equal zero. Using the earlier NPV equation but with cash flow:

$$\text{NPV(Cash Flow)} = \Sigma_t \text{ Cash Flow}_t \times (1 + \text{IRR})^{t-t_0} = 0.0.$$

The value is found through iteration and is built into the spreadsheet software.

A.2.3.3. Internal Rate of Return - Equity

Equity cash flow is the basis for calculating the internal rate of return to equity holders. It can be calculated either through use of the income statement and adjustments based on noncash expenses and revenues, or through a bottoms-up summation of cash inflows and outflows.

Equity Cash Flow = Cash Revenues + Debt Issued – Capital Outlays – Fuel Costs – O&M Costs – Change in Working Capital – Interest Payment – Debt Retirement –Taxes

or

Equity Cash Flow = Net Income + Depreciation + AFUDC Depreciation + Deferred Taxes + Debt Issued - Capital Outlays – Debt Retired – AFUDC.

Equity cash flow represents the funds either received from or paid out to the parent utility. The funds may be from internally generated sources within the utility or from stock issues. Funds out may be paid to stockholders as dividends or used to fund other projects of the utility. The original source or ultimate use of the equity funds outside this model are not important to this study.

The Internal Rate of Return - Equity (IRR-Equity) uses the same NPV equation as the IRR but uses the equity cashflow instead of the project cash flow.

A.3. NONUTILITY GENERATORS

A.3.1. Overview

In Fig. A.2, we summarize how the financial regulatory model determines net income for a NUG. In contrast to IOUs (Fig. A.1) there are no ratemaking procedures for NUGs.

A.3.2. Components of Net Income

A.3.2.1. Revenues

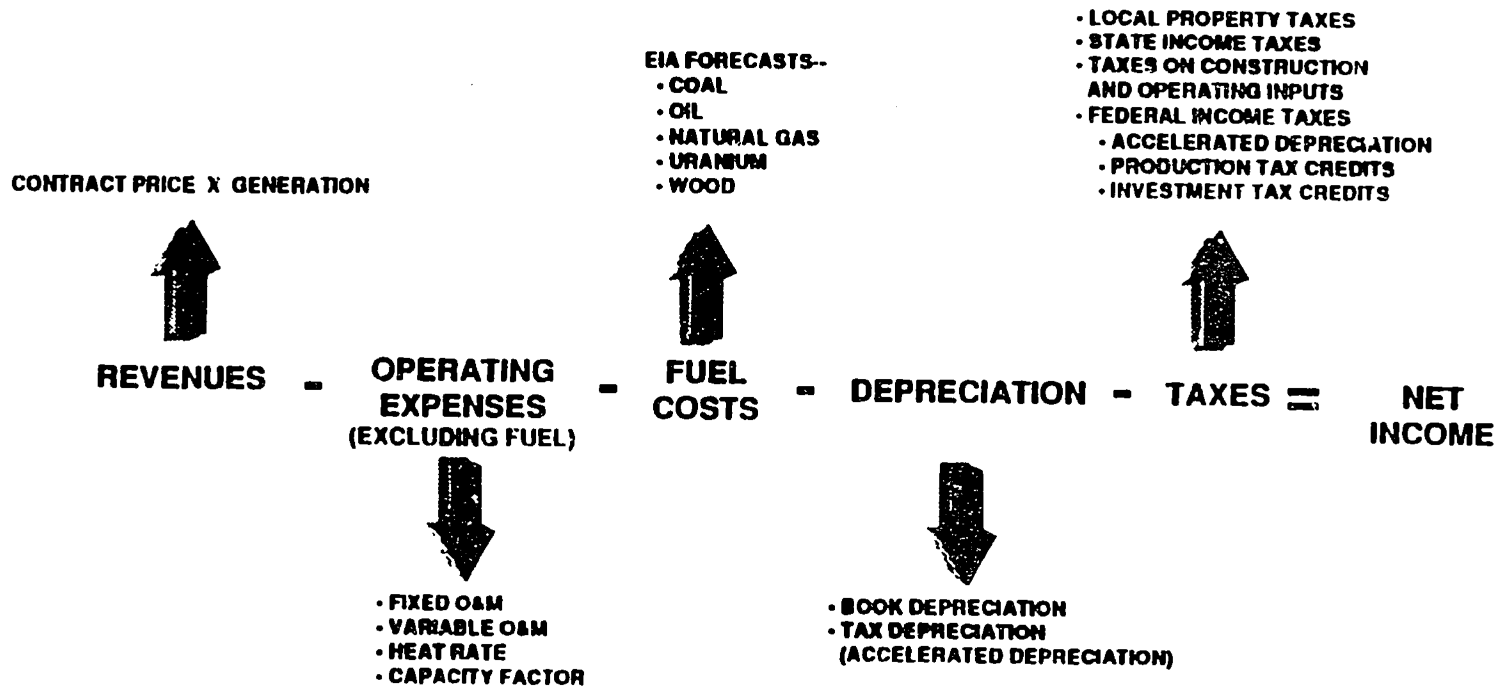
Revenues for NUGs are a single input price multiplied by the electricity production to calculate revenues. This simulates a fixed price contract with a utility based on an agreed-upon price, such as avoided cost in the year of the contract. Since these cases used real rates of return with no escalation for inflation, this is equivalent to having a price set at the beginning of plant operation but escalating with general inflation. In reality, NUG contracts are much more complex, involving many more variables in prices, terms, conditions, and time periods; but analysis of the consequences of such variables is beyond the scope of this study.

A.3.2.2. Fuel Costs

See the discussion in Sect. A.2.2.1.

FIGURE A.2

NET INCOME FOR NON-UTILITY GENERATORS



A.3.2.3. Other O&M Expenses

See the discussion in Sect. A.2.2.2.

A.3.2.4. Depreciation

See the discussion in Sect. A.2.2.3.

A.2.2.4. Taxes

Taxes are calculated the same for NUGs as for IOUs (Sect. A.2.2.4) except that we include two options. The first option is that the AMT applies to the NUG. The second option is that operating losses have to be carried forward rather than causing income taxes to be negative.

The AMT applies if a corporation relies too much on tax benefits such as accelerated depreciation to lower its tax bill. The AMT reduces those tax advantages but uses a lower tax rate in calculating the alternative tax. The model calculates tax depreciation using the longer depreciation life specified in the tax code. It then determines an AMT Income based on normal revenues, expenses, and this new depreciation amount. It multiplies the AMT Income by 20% to find the AMT. If this amount is higher than the regular tax that would have been paid (or a smaller tax credit for operating losses), the AMT is used instead of the regular tax.

Alternative Minimum Tax = (Revenues - Alternative Depreciation -Other Expenses) x 20%

Current Taxes Payable = Maximum (Regular Current Taxes, Alternative Minimum Tax)

Carryforward of operating losses is required if the NUG does not have sufficient offsetting positive taxes elsewhere in its operations to use these operating losses. In this case, it must carry the losses forward until they can be used to offset positive taxes (see Sect. 4).

For example, in year t, suppose net income before income taxes is -\$100K. State and federal income taxes would be -\$6K and -\$33K respectively. Because taxes could not be negative, the -\$39K would be carried forward to apply against any positive taxes in the next year. In year t + 1, net income before income taxes is again -\$100K. The resultant -\$39K in taxes would also be carried forward. In Year t + 2, net income is +\$60K. Taxes would be \$23K. The model would use the carry forward from year t to offset these positive taxes first. This would leave year t carryforward at -\$16K and year t + 1 at -\$39K. If at the end of year t + 15 any part of the remaining -\$16K had not been used to offset taxes, those credits would be lost to the corporation.

The net income before income taxes is based on using the accelerated depreciation of the project, as opposed to the book depreciation. This means that plants

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with high depreciation due to accelerated depreciation may show a profit on the regular income statement but have large losses on the tax income statement. These losses are what are carried forward in the tax calculation.

Although tax law allows a carryback and carryforward of losses, with carryback preferred, the model uses only carryforward of losses. This is because losses generally occur at start-up before there are positive taxes to offset the losses. The credits are not carried on the balance sheet as receivables but only taken as extraordinary gains if used.

A.3.3. Decisionmaking Criteria

A.3.3.1. Internal Rate of Return

See Sect. A.2.3.2 for the discussion on IRR. For the NUG cases, the internal rate of return for combined Debt + Equity is used. This criterion helps show whether the project as a whole has an adequate return, apart from the financing ratio of debt to equity. (However, the tax deductibility of interest does affect the overall return of the project.)

A.3.3.2. Internal Rate of Return - Equity

See Sect. A.2.3.3 for the discussion on IRR-Equity. This number represents the profitability of the project to the equity shareholders. Because of the amount of leverage involved (use of debt at a fixed interest rate), this criterion is similar to the IRR for the project but is very amplified. Increases in IRR of a few percentage points give increases in the IRR-Equity of tens of percentage points. Decreases in the IRR can make the IRR-Equity negative.

There is an additional complication in the IRR-Equity calculation. Because we modeled a generic debt repayment over the life of the plant without regard to funding availability, there are some cases where equity net cash flow becomes negative starting some years after the plant comes on-line. It may then turn positive again in the last years of operation as the interest payments and other costs decline relative to the fixed revenue stream. This causes an equity cash flow profile that is negative during construction, positive in the early years during accelerated depreciation, negative for some years, and maybe positive in the last few years. The IRR function may not give accurate results under these circumstances. It can actually give higher a IRR value with a lower net cash flow because a higher IRR reduces the weighting of the negative cash flow in the latter years.

APPENDIX B: SIMULATION RESULTS

Table B.1
Tax Simulation Results:
Levelized Cost and Internal Rate of Return, Investor-Owned Utilities
(Levelized Cost in ¢/kWh, IRR in %)

GENERATING ALTERNATIVE	Reference Base Tech with Taxes	No Taxes or Credits	No Property Taxes	No Input Taxes	No State Income Taxes	No Credits and No Fed. Income Tax
RENEWABLES						
Biomass-Plantation						
Levelized Cost	6.05	6.21	5.57	5.63	6.09	7.08
Int. Rate of Return	5.91%	6.00%	5.91%	5.91%	5.92%	5.99%
Biomass-Waste						
Levelized Cost	6.49	5.46	6.02	6.11	6.46	6.29
Int. Rate of Return	5.91%	6.00%	5.91%	5.91%	5.92%	5.99%
Geothermal						
Levelized Cost	6.16	5.29	5.53	5.75	6.19	6.30
Int. Rate of Return	5.70%	6.00%	5.70%	5.70%	5.74%	5.96%
Hydro						
Levelized Cost	2.90	2.07	2.34	2.71	2.88	2.79
Int. Rate of Return	5.85%	6.00%	5.85%	5.85%	5.87%	5.98%
Solar-Photovoltaic						
Levelized Cost	32.37	25.53	25.43	30.23	32.68	34.14
Int. Rate of Return	5.65%	6.00%	5.65%	5.66%	5.70%	5.96%
Solar-Thermal						
Levelized Cost	16.33	13.17	13.27	15.24	16.46	17.10
Int. Rate of Return	5.66%	6.00%	5.66%	5.66%	5.70%	5.96%
Wind						
Levelized Cost	3.30	3.65	2.52	3.00	3.40	4.68
Int. Rate of Return	5.69%	6.00%	5.69%	5.69%	5.73%	5.96%
CONVENTIONAL						
Coal						
Levelized Cost	5.90	4.85	5.41	5.54	5.87	5.68
Int. Rate of Return	5.91%	6.00%	5.91%	5.91%	5.92%	5.99%
Combined Cycle						
Levelized Cost	6.06	5.14	5.65	5.72	6.03	5.89
Int. Rate of Return	5.91%	6.00%	5.91%	5.91%	5.92%	5.99%
Combustion Turbine						
Levelized Cost	9.13	7.77	8.40	8.61	9.10	8.97
Int. Rate of Return	5.85%	6.00%	5.85%	5.85%	5.87%	5.98%
Nuclear						
Levelized Cost	5.75	4.78	5.28	5.37	5.73	5.60
Int. Rate of Return	5.88%	6.00%	5.88%	5.88%	5.89%	5.98%

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Table B.2
Ratemaking Simulation Results:
Levelized Cost and Internal Rate of Return,
Investor-Owned Utilities
(Levelized Cost in ¢/kWh, IRR in %)

GENERATING ALTERNATIVE	Reference Base Tech with Taxes	CWIP Allowed	Flow-Through Taxes	No Fuel Adjustment Clause
RENEWABLES				
Biomass-Plantation				
Levelized Cost	6.05	6.06	6.19	6.05
Int. Rate of Return	5.91%	5.92%	6.00%	5.91%
Biomass-Waste				
Levelized Cost	6.49	6.50	6.63	6.49
Int. Rate of Return	5.91%	5.92%	6.00%	5.91%
Geothermal				
Levelized Cost	6.16	6.17	6.54	6.16
Int. Rate of Return	5.70%	5.69%	6.00%	5.70%
Hydro				
Levelized Cost	2.90	2.91	3.22	2.90
Int. Rate of Return	5.85%	5.86%	6.00%	5.85%
Solar-Photovoltaic				
Levelized Cost	32.37	32.39	36.48	32.37
Int. Rate of Return	5.65%	5.65%	6.00%	5.65%
Solar-Thermal				
Levelized Cost	16.33	16.34	18.14	16.33
Int. Rate of Return	5.66%	5.65%	6.00%	5.66%
Wind				
Levelized Cost	3.30	3.31	3.73	3.30
Int. Rate of Return	5.69%	5.69%	6.00%	5.69%
CONVENTIONAL				
Coal				
Levelized Cost	5.90	5.92	6.05	5.90
Int. Rate of Return	5.91%	5.92%	6.00%	5.91%
Combined Cycle				
Levelized Cost	6.06	6.07	6.19	6.06
Int. Rate of Return	5.91%	5.92%	6.00%	5.88%
Combustion Turbine				
Levelized Cost	9.13	9.13	9.34	9.12
Int. Rate of Return	5.85%	5.85%	6.00%	5.82%
Nuclear				
Levelized Cost	5.75	5.77	5.90	5.75
Int. Rate of Return	5.88%	5.89%	6.00%	5.88%

Table B.3
Summary of Federal Income Tax Simulation Results: Levelized Cost and Internal Rate of Return, Investor-Owned Utilities
(Levelized Cost in ¢/kWh, IRR in %)

GENERATING ALTERNATIVE	Reference	No Credits and No Fed. Income Tax	Tax Life = Book Life	No Credits	No Credits or Accel Dep.
RENEWABLES					
Biomass-Plantation					
Levelized Cost	6.05	7.08	6.22	7.29	7.46
Int. Rate of Return	5.91%	5.99%	5.99%	5.91%	5.99%
Biomass-Waste					
Levelized Cost	6.49	6.29	6.67	6.49	6.67
Int. Rate of Return	5.91%	5.99%	5.99%	5.91%	5.99%
Geothermal					
Levelized Cost	6.16	6.30	6.84	6.16	6.64
Int. Rate of Return	5.70%	5.96%	5.99%	5.70%	5.99%
Hydro					
Levelized Cost	2.90	2.79	3.24	2.90	3.24
Int. Rate of Return	5.85%	5.98%	5.98%	5.85%	5.98%
Solar-Photovoltaic					
Levelized Cost	32.37	34.14	39.85	32.37	39.85
Int. Rate of Return	5.65%	5.96%	6.00%	5.65%	6.00%
Solar-Thermal					
Levelized Cost	16.33	17.10	19.62	16.33	19.62
Int. Rate of Return	5.66%	5.96%	6.00%	5.66%	6.00%
Wind					
Levelized Cost	3.30	4.68	4.08	4.54	5.31
Int. Rate of Return	5.69%	5.96%	6.00%	5.69%	6.00%
CONVENTIONAL					
Coal					
Levelized Cost	5.90	5.68	6.08	5.90	6.08
Int. Rate of Return	5.91%	5.99%	5.99%	5.91%	5.99%
Combined Cycle					
Levelized Cost	6.06	5.89	6.21	6.06	6.21
Int. Rate of Return	5.91%	5.99%	5.99%	5.91%	5.99%
Combustion Turbine					
Levelized Cost	9.13	8.97	9.53	9.13	9.53
Int. Rate of Return	5.85%	5.98%	6.00%	5.85%	6.00%
Nuclear					
Levelized Cost	5.75	5.60	6.01	5.75	6.01
Int. Rate of Return	5.88%	5.98%	5.98%	5.88%	5.98%

Table B.4
Summary of Property Tax Simulation Results: Levelized Cost and Internal Rate of Return, Investor-Owned Utilities
(Levelized Cost in ¢/kWh, IRR in %)

GENERATING ALTERNATIVE	No Property Tax	Tax Based on Net Book Value (Reference)	Tax Based on Gross Book Value	Tax Based on Future Cash Flow	Tax Based on Net Book Value + No Tax on Land
RENEWABLES					
Biomass-Plantation					
Levelized Cost	5.57	6.05	6.34	6.06	6.01
Int. Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%
Biomass-Waste					
Levelized Cost	6.02	6.49	6.78	6.50	6.46
Int. Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%
Geothermal					
Levelized Cost	5.53	6.16	6.55	6.04	6.11
Int. Rate of Return	5.70%	5.70%	5.70%	5.70%	5.70%
Hydro					
Levelized Cost	2.34	2.90	3.15	2.89	2.86
Int. Rate of Return	5.85%	5.85%	5.85%	5.85%	5.85%
Solar-Photovoltaic					
Levelized Cost	25.43	32.37	36.63	30.58	31.84
Int. Rate of Return	5.65%	5.65%	5.65%	5.65%	5.65%
Solar-Thermal					
Levelized Cost	13.27	16.33	18.20	15.55	16.09
Int. Rate of Return	5.66%	5.66%	5.66%	5.66%	5.66%
Wind					
Levelized Cost	2.52	3.30	3.74	3.13	3.19
Int. Rate of Return	5.69%	5.69%	5.69%	5.69%	5.69%
CONVENTIONAL					
Coal					
Levelized Cost	5.41	5.90	6.21	5.93	5.87
Int. Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%
Combined Cycle					
Levelized Cost	5.65	6.06	6.32	6.07	6.03
Int. Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%
Combustion Turbine					
Levelized Cost	8.40	9.13	9.57	9.06	9.07
Int. Rate of Return	5.85%	5.85%	5.85%	5.85%	5.85%
Nuclear					
Levelized Cost	5.28	5.75	6.04	5.77	5.72
Int. Rate of Return	5.88%	5.88%	5.88%	5.88%	5.88%

Table B.5
Summary of State Input Tax Effects:
Levelized Cost and Internal Rate of Return,
Investor-Owned Utilities
(Levelized Cost in ¢/kWh, IRR in %)

GENERATING ALTERNATIVE	Reference	No Input Taxes	No Labor Tax	No Energy Tax	No Material Tax	No Land Tax
RENEWABLES						
Biomass-Plantation						
Levelized Cost	6.05	5.63	5.90	5.87	5.97	6.04
Int. Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
Biomass-Waste						
Levelized Cost	6.49	6.11	6.35	6.35	6.42	6.49
Int. Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
Geothermal						
Levelized Cost	6.16	5.75	5.90	6.16	6.02	6.15
Int. Rate of Return	5.70%	5.70%	5.70%	5.70%	5.70%	5.70%
Hydro						
Levelized Cost	2.90	2.71	2.78	2.89	2.84	2.89
Int. Rate of Return	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
Solar-Photovoltaic						
Levelized Cost	32.37	30.23	31.07	32.30	31.69	32.29
Int. Rate of Return	5.65%	5.66%	5.66%	5.66%	5.66%	5.66%
Solar-Thermal						
Levelized Cost	16.33	15.24	15.66	16.29	15.98	16.29
Int. Rate of Return	5.66%	5.66%	5.66%	5.66%	5.66%	5.66%
Wind						
Levelized Cost	3.30	3.00	3.12	3.30	3.21	3.29
Int. Rate of Return	5.69%	5.69%	5.69%	5.69%	5.69%	5.69%
CONVENTIONAL						
Coal						
Levelized Cost	5.90	5.54	5.73	5.81	5.81	5.90
Int. Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
Combined Cycle						
Levelized Cost	6.06	5.72	5.94	5.90	6.00	6.06
Int. Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
Combustion Turbine						
Levelized Cost	9.13	8.61	8.95	8.89	9.04	9.12
Int. Rate of Return	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
Nuclear						
Levelized Cost	5.75	5.37	5.53	5.72	5.64	5.75
Int. Rate of Return	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%

Table B.6
Tax Simulation Results:
Internal Rate of Return and Internal Rate of Return-Equity, Nonutility Generators

GENERATING ALTERNATIVE	Reference Base Tech with Taxes	No Taxes or Credits	No Property Taxes	No Input Taxes	No State Income Taxes	No Credits and No Fed. Income Tax	Alternative Minimum Tax
RENEWABLES							
Biomass-Plantation							
Int. Rate of Rtrn %	7.93%	5.19%	9.79%	9.55%	7.54%	1.43%	5.43%
IRR - Equity %	27.21%	5.56%	33.02%	31.83%	24.61%	a	9.55%
Biomass-Waste							
Int. Rate of Rtrn %	7.28%	10.26%	8.83%	8.47%	7.22%	6.85%	5.60%
IRR - Equity %	17.38%	21.03%	24.41%	22.02%	16.02%	10.49%	7.44%
Geothermal							
Int. Rate of Rtrn %	7.31%	8.86%	8.98%	8.39%	7.18%	5.67%	5.46%
IRR - Equity %	22.11%	16.60%	29.72%	26.31%	19.81%	6.93%	7.30%
Hydro							
Int. Rate of Rtrn %	6.10%	8.61%	7.39%	6.55%	6.11%	6.16%	5.53%
IRR - Equity %	8.57%	15.11%	13.02%	10.01%	8.48%	7.98%	6.59%
Solar-Photovoltaic							
Int. Rate of Rtrn %	7.33%	8.16%	9.33%	7.94%	7.15%	5.30%	5.19%
IRR - Equity %	32.69%	15.40%	44.63%	35.73%	28.17%	5.91%	6.15%
Solar-Thermal							
Int. Rate of Rtrn %	7.36%	8.30%	9.35%	8.05%	7.18%	5.34%	5.23%
IRR - Equity %	32.80%	15.88%	44.69%	36.25%	28.30%	6.03%	6.34%
Wind							
Int. Rate of Rtrn %	6.49%	4.82%	8.66%	7.37%	6.16%	1.81%	4.19%
IRR - Equity %	26.09%	4.41%	36.81%	30.37%	21.67%	a	a
CONVENTIONAL							
Coal							
Int. Rate of Rtrn %	6.29%	9.91%	7.53%	7.21%	6.36%	6.79%	6.08%
IRR - Equity %	9.39%	18.97%	13.59%	12.20%	9.49%	10.10%	8.56%
Combined Cycle							
Int. Rate of Rtrn %	6.56%	11.71%	8.17%	7.89%	6.65%	7.28%	6.43%
IRR - Equity %	13.32%	29.53%	19.52%	17.85%	13.62%	15.60%	12.64%
Combustion Turbine							
Int. Rate of Rtrn %	6.55%	11.62%	8.43%	7.89%	6.58%	6.82%	6.16%
IRR - Equity %	15.53%	34.85%	24.10%	20.84%	15.50%	15.32%	13.35%
Nuclear							
Int. Rate of Rtrn %	6.28%	9.39%	7.41%	7.20%	6.31%	6.54%	5.89%
IRR - Equity %	9.13%	16.50%	12.78%	11.84%	9.11%	9.01%	7.76%

a Internal Rate of Return-Equity cannot be calculated for these cases because the equity cash flow profile is such that no discount rate will give a zero net present value over the entire life of the project.

Table B.7
Summary of Federal Income Tax Simulation Results:
Internal Rate of Return and Internal Rate of Return-Equity,
Nonutility Generators

GENERATING ALTERNATIVE	Reference	No Credits and No Fed. Income Tax	Tax Life = Book Life	No Tax Credits	No Credits or Accel Dep.
RENEWABLES					
Biomass-Plantation					
Int. Rate of Rtrn %	7.93%	1.43%	6.10%	2.89%	2.21%
IRR - Equity %	27.21%	a	11.03%	a	a
Biomass-Waste					
Int. Rate of Rtrn %	7.28%	6.85%	5.88%	7.28%	5.88%
IRR - Equity %	17.38%	10.49%	7.72%	17.38%	7.72%
Geothermal					
Int. Rate of Rtrn %	6.26%	4.40%	4.92%	5.28%	4.19%
IRR - Equity %	17.01%	3.28%	4.71%	6.90%	2.47%
Hydro					
Int. Rate of Rtrn %	6.10%	6.16%	5.50%	6.10%	5.50%
IRR - Equity %	8.57%	7.98%	6.39%	8.57%	6.39%
Solar-Photovoltaic					
Int. Rate of Rtrn %	6.08%	3.87%	4.61%	4.96%	3.92%
IRR - Equity %	25.15%	1.66%	3.48%	4.63%	1.24%
Solar-Thermal					
Int. Rate of Rtrn %	6.12%	3.91%	4.64%	4.99%	3.85%
IRR - Equity %	25.33%	1.78%	3.59%	4.94%	1.33%
Wind					
Int. Rate of Rtrn %	6.49%	1.81%	4.94%	3.19%	2.47%
IRR - Equity %	26.09%	a	4.68%	a	a
CONVENTIONAL					
Coal					
Int. Rate of Rtrn %	6.29%	6.79%	5.93%	6.29%	5.93%
IRR - Equity %	9.39%	10.10%	7.90%	9.39%	7.90%
Combined Cycle					
Int. Rate of Rtrn %	6.56%	7.28%	6.07%	6.56%	6.07%
IRR - Equity %	13.32%	15.60%	10.38%	13.32%	10.38%
Combustion Turbine					
Int. Rate of Rtrn %	6.55%	6.82%	5.70%	6.55%	5.70%
IRR - Equity %	15.53%	15.32%	9.04%	15.53%	9.04%
Nuclear					
Int. Rate of Rtrn %	6.28%	6.54%	5.77%	6.28%	5.77%
IRR - Equity %	9.13%	9.01%	7.21%	9.13%	7.21%

a Internal Rate of Return-Equity cannot be calculated for these cases because the equity cash flow profile is such that no discount rate will give a zero net present value over the entire life of the project.

Table B.8
Summary of Alternative Minimum Tax Results:
Internal Rate of Return and Internal Rate of Return-Equity,
Nonutility Generators

GENERATING ALTERNATIVE	Reference	Alternative Minimum Tax	Carry Forward of Tax Losses	Alternative Min. Tax and Carry Forward
RENEWABLES				
Biomass-Plantation				
Int. Rate of Rtm %	7.93%	5.43%	1.14%	1.14%
IRR - Equity %	27.21%	9.55%	a	a
Biomass-Waste				
Int. Rate of Rtrn %	7.28%	5.63%	6.13%	5.40%
IRR - Equity %	17.38%	7.44%	8.59%	6.36%
Geothermal				
Int. Rate of Rtm %	6.26%	4.37%	3.97%	3.65%
IRR - Equity %	17.01%	1.73%	1.99%	0.69%
Hydro				
Int. Rate of Rtm %	6.10%	5.53%	5.61%	5.44%
IRR - Equity %	8.57%	6.59%	6.73%	6.26%
Solar-Photovoltaic				
Int. Rate of Rtm %	6.08%	3.94%	3.42%	3.15%
IRR - Equity %	25.15%	a	0.28%	a
Solar-Thermal				
Int. Rate of Rtm %	6.12%	3.98%	3.46%	3.19%
IRR - Equity %	25.33%	a	0.41%	a
Wind				
Int. Rate of Rtm %	6.49%	4.19%	1.54%	1.54%
IRR - Equity %	26.09%	a	a	a
CONVENTIONAL				
Coal				
Int. Rate of Rtm %	6.29%	6.08%	6.17%	6.04%
IRR - Equity %	9.39%	8.56%	8.75%	8.35%
Combined Cycle				
Int. Rate of Rtm %	6.56%	6.43%	6.54%	6.42%
IRR - Equity %	13.32%	12.64%	13.12%	12.52%
Combustion Turbine				
Int. Rate of Rtm %	6.55%	6.16%	6.43%	6.14%
IRR - Equity %	15.53%	13.35%	14.37%	13.15%
Nuclear				
Int. Rate of Rtm %	6.28%	5.89%	5.89%	5.75%
IRR - Equity %	9.13%	7.76%	7.58%	7.20%

a Internal Rate of Return-Equity cannot be calculated for these cases because the equity cash flow profile is such that no discount rate will give a zero net present value over the entire life of the project.

Table B.9
Levelized Cost Components (¢/kWh),
Biomass/Dedicated Plant

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop. Tax	Tax Credit	Total Cost
Reference	1.82	0.84	3.57	-0.12	0.22	0.48	-0.75	6.05
No Taxes	1.80	0.84	3.57	0.00	0.00	0.00	0.00	6.21
No Property Tax	1.82	0.84	3.57	-0.12	0.22	0.00	-0.75	5.57
No Input Taxes	1.69	0.84	3.57	-0.14	-0.03	0.45	-0.75	5.63
No State Income Tax	1.83	0.84	3.57	-0.11	0.24	0.48	-0.75	6.09
No Fed Tax/Credits	1.92	0.84	3.57	0.00	0.28	0.48	0.00	7.08
Tax Life = Book	1.92	0.84	3.57	-0.06	0.23	0.48	-0.75	6.22
No Tax Credits	1.82	0.84	3.57	0.29	0.29	0.48	0.00	7.29
CWIP	1.82	0.84	3.57	-0.11	0.22	0.48	-0.75	6.06
Flow-Thru Taxes	1.93	0.84	3.57	-0.10	0.22	0.48	-0.75	6.19
No Fuel Adj. Clause	1.82	0.84	3.57	-0.12	0.22	0.48	-0.75	6.05

Table B.10
Levelized Cost Components (¢/kWh),
Biomass/Waste Wood

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop. Tax	Tax Credit	Total Cost
Reference	1.82	0.84	2.82	0.29	0.26	0.48	0.00	6.49
No Taxes	1.80	0.84	2.82	0.00	0.00	0.00	0.00	5.46
No Property Tax	1.82	0.84	2.82	0.29	0.26	0.00	0.00	6.02
No Input Taxes	1.69	0.84	2.82	0.27	0.05	0.45	0.00	6.11
No State Income Tax	1.83	0.84	2.82	0.29	0.20	0.48	0.00	6.46
No Fed Tax/Credits	1.92	0.84	2.82	0.00	0.24	0.48	0.00	6.29
Tax Life = Book	1.92	0.84	2.82	0.35	0.27	0.48	0.00	6.67
No Tax Credits	1.82	0.84	2.82	0.29	0.26	0.48	0.00	6.49
CWIP	1.82	0.84	2.82	0.29	0.26	0.48	0.00	6.50
Flow-Thru Taxes	1.93	0.84	2.82	0.31	0.26	0.48	0.00	6.63
No Fuel Adj. Clause	1.82	0.84	2.82	0.29	0.26	0.48	0.00	6.49

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Table B.11
Levelized Cost Components (¢/kWh),
Geothermal

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop Tax	Tax Credit	Total Cost
Reference	2.14	2.90	0.00	0.24	0.26	0.63	0.00	6.16
No Taxes	2.39	2.90	0.00	0.00	0.00	0.00	0.00	5.29
No Property Tax	2.14	2.90	0.00	0.24	0.26	0.00	0.00	5.53
No Input Taxes	2.00	2.90	0.00	0.23	0.04	0.59	0.00	5.75
No State Income Tax	2.18	2.90	0.00	0.26	0.22	0.63	0.00	6.19
No Fed Tax/Credits	2.50	2.90	0.00	0.00	0.27	0.63	0.00	6.30
Tax Life = Book	2.55	2.90	0.00	0.46	0.30	0.63	0.00	6.84
No Tax Credits	2.14	2.90	0.00	0.24	0.26	0.63	0.00	6.16
CWIP	2.14	2.90	0.00	0.24	0.26	0.63	0.00	6.17
Flow-Thru Taxes	2.57	2.90	0.00	0.19	0.25	0.63	0.00	6.54
No Fuel Adj. Clause	2.14	2.90	0.00	0.24	0.26	0.63	0.00	6.16

Table B.12
Levelized Cost Components (¢/kWh), Hydro

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop. Tax	Tax Credit	Total Cost
Reference	1.62	0.34	0.00	0.30	0.08	0.56	0.00	2.90
No Taxes	1.73	0.34	0.00	0.00	0.00	0.00	0.00	2.07
No Property Tax	1.62	0.34	0.00	0.30	0.08	0.00	0.00	2.34
No Input Taxes	1.52	0.34	0.00	0.28	0.05	0.52	0.00	2.71
No State Income Tax	1.65	0.34	0.00	0.31	0.03	0.56	0.00	2.88
No Fed Tax/Credits	1.82	0.34	0.00	0.00	0.07	0.56	0.00	2.79
Tax Life = Book	1.83	0.34	0.00	0.41	0.10	0.56	0.00	3.24
No Tax Credits	1.62	0.34	0.00	0.30	0.08	0.56	0.00	2.90
CWIP	1.63	0.34	0.00	0.30	0.08	0.56	0.00	2.91
Flow-Thru Taxes	1.86	0.34	0.00	0.37	0.09	0.56	0.00	3.22
No Fuel Adj. Clause	1.62	0.34	0.00	0.30	0.08	0.56	0.00	2.90

Table B.13
Levelized Cost Components (¢/kWh), Solar/Photovoltaic

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop Tax	Tax Credit	Total Cost
Reference	22.28	0.47	0.00	2.26	0.42	6.95	0.00	32.37
No Taxes	25.07	0.47	0.00	0.00	0.00	0.00	0.00	25.53
No Property Tax	22.28	0.47	0.00	2.26	0.42	0.00	0.00	25.43
No Input Taxes	20.78	0.47	0.00	2.13	0.36	6.49	0.00	30.23
No State Income Tax	22.74	0.47	0.00	2.49	0.03	6.95	0.00	32.68
No Fed Tax/Credits	26.18	0.47	0.00	0.00	0.55	6.95	0.00	34.14
Tax Life = Book	26.85	0.47	0.00	4.70	0.89	6.95	0.00	39.85
No Tax Credits	22.28	0.47	0.00	2.26	0.42	6.95	0.00	32.37
CWIP	22.28	0.47	0.00	2.27	0.42	6.95	0.00	32.39
Flow-Thru Taxes	26.89	0.47	0.00	1.81	0.36	6.95	0.00	36.48
No Fuel Adj. Clause	22.28	0.47	0.00	2.26	0.42	6.95	0.00	32.37

Table B.14
Levelized Cost Components (¢/kWh), Solar/Thermal

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop Tax	Tax Credit	Total Cost
Reference	9.83	2.10	0.00	1.00	0.33	3.06	0.00	16.33
No Taxes	11.06	2.10	0.00	0.00	0.00	0.00	0.00	13.17
No Property Tax	9.83	2.10	0.00	1.00	0.33	0.00	0.00	13.27
No Input Taxes	9.17	2.10	0.00	0.94	0.16	2.86	0.00	15.24
No State Income Tax	10.04	2.10	0.00	1.10	0.16	3.06	0.00	16.46
No Fed Tax/Credits	11.55	2.10	0.00	0.00	0.38	3.06	0.00	17.10
Tax Life = Book	11.85	2.10	0.00	2.08	0.53	3.06	0.00	19.62
No Tax Credits	9.83	2.10	0.00	1.00	0.33	3.06	0.00	16.33
CWIP	9.84	2.10	0.00	1.01	0.33	3.06	0.00	16.34
Flow-Thru Taxes	11.87	2.10	0.00	0.80	0.30	3.06	0.00	18.14
No Fuel Adj. Clause	9.83	2.10	0.00	1.00	0.33	3.06	0.00	16.33

Table B.15
Levelized Cost Components (¢/kWh),
Wind

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop. Tax	Tax Credit	Total Cost
Reference	2.44	0.93	0.00	-0.13	0.04	0.78	-0.75	3.30
No Taxes	2.72	0.93	0.00	0.00	0.00	0.00	0.00	3.65
No Property Tax	2.44	0.93	0.00	-0.13	0.04	0.00	-0.75	2.52
No Input Taxes	2.27	0.93	0.00	-0.15	-0.03	0.73	-0.75	3.00
No State Income Tax	2.49	0.93	0.00	-0.11	0.07	0.78	-0.75	3.40
No Fed Tax/Credits	2.84	0.93	0.00	0.00	0.13	0.78	0.00	4.68
Tax Life = Book	2.91	0.93	0.00	0.12	0.09	0.78	-0.75	4.08
No Tax Credits	2.44	0.93	0.00	0.28	0.12	0.78	0.00	4.54
CWIP	2.44	0.93	0.00	-0.13	0.04	0.78	-0.75	3.31
Flow-Thru Taxes	2.91	0.93	0.00	-0.18	0.04	0.78	-0.75	3.73
No Fuel Adj. Clause	2.44	0.93	0.00	-0.13	0.04	0.78	-0.75	3.30

Table B.16
Levelized Cost Components (¢/kWh), Coal

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop. Tax	Tax Credit	Total Cost
Reference	1.97	1.15	1.74	0.32	0.23	0.49	0.00	5.90
No Taxes	1.96	1.15	1.74	0.00	0.00	0.00	0.00	4.85
No Property Tax	1.97	1.15	1.74	0.32	0.23	0.00	0.00	5.41
No Input Taxes	1.84	1.15	1.74	0.30	0.05	0.46	0.00	5.54
No State Income Tax	1.98	1.15	1.74	0.33	0.17	0.49	0.00	5.87
No Fed Tax/Credits	2.08	1.15	1.74	0.00	0.22	0.49	0.00	5.68
Tax Life = Book	2.08	1.15	1.74	0.38	0.24	0.49	0.00	6.08
No Tax Credits	1.97	1.15	1.74	0.32	0.23	0.49	0.00	5.90
CWIP	1.97	1.15	1.74	0.33	0.23	0.49	0.00	5.92
Flow-Thru Taxes	2.10	1.15	1.74	0.34	0.23	0.49	0.00	6.05
No Fuel Adj. Clause	1.97	1.15	1.74	0.32	0.23	0.49	0.00	5.90

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Table B.17
Levelized Cost Components (¢/kWh), Combined Cycle

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop. Tax	Tax Credit	Total Cost
Reference	1.59	0.50	3.06	0.25	0.24	0.42	0.00	6.06
No Taxes	1.58	0.50	3.06	0.00	0.00	0.00	0.00	5.14
No Property Tax	1.59	0.50	3.06	0.25	0.24	0.00	0.00	5.65
No Input Taxes	1.48	0.50	3.06	0.24	0.04	0.39	0.00	5.72
No State Income Tax	1.60	0.50	3.06	0.26	0.19	0.42	0.00	6.03
No Fed Tax/Credits	1.68	0.50	3.06	0.00	0.23	0.42	0.00	5.89
Tax Life = Book	1.68	0.50	3.06	0.30	0.25	0.42	0.00	6.21
No Tax Credits	1.59	0.50	3.06	0.25	0.24	0.42	0.00	6.06
CWIP	1.59	0.50	3.06	0.26	0.24	0.42	0.00	6.07
Flow-Thru Taxes	1.69	0.50	3.06	0.27	0.24	0.42	0.00	6.19
No Fuel Adj. Clause	1.59	0.50	3.06	0.25	0.24	0.42	0.00	6.06

Table B.18
Levelized Cost Components (¢/kWh),
Combustion Turbine

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop. Tax	Tax Credit	Total Cost
Reference	2.56	0.52	4.63	0.36	0.33	0.73	0.00	9.13
No Taxes	2.62	0.52	4.63	0.00	0.00	0.00	0.00	7.77
No Property Tax	2.56	0.52	4.63	0.36	0.33	0.00	0.00	8.40
No Input Taxes	2.39	0.52	4.63	0.34	0.06	0.68	0.00	8.61
No State Income Tax	2.59	0.52	4.63	0.37	0.27	0.73	0.00	9.10
No Fed Tax/Credits	2.77	0.52	4.63	0.00	0.33	0.73	0.00	8.97
Tax Life = Book	2.81	0.52	4.63	0.49	0.36	0.73	0.00	9.53
No Tax Credits	2.56	0.52	4.63	0.36	0.33	0.73	0.00	9.13
CWIP	2.56	0.52	4.63	0.36	0.33	0.73	0.00	9.13
Flow-Thru Taxes	2.81	0.52	4.63	0.33	0.33	0.73	0.00	9.34
No Fuel Adj. Clause	2.56	0.52	4.62	0.36	0.33	0.73	0.00	9.12

Table B.19
Levelized Cost Components (¢/kWh), Nuclear

	Capital	O&M Cost	Fuel Cost	Fed. Tax	State/Local	Prop. Tax	Tax Credit	Total Cost
Reference	1.89	2.38	0.46	0.30	0.25	0.47	0.00	5.75
No Taxes	1.94	2.38	0.46	0.00	0.00	0.00	0.00	4.78
No Property Tax	1.89	2.38	0.46	0.30	0.25	0.00	0.00	5.28
No Input Taxes	1.76	2.38	0.46	0.28	0.05	0.44	0.00	5.37
No State Income Tax	1.91	2.38	0.46	0.31	0.20	0.47	0.00	5.73
No Fed Tax/Credits	2.05	2.38	0.46	0.00	0.25	0.47	0.00	5.60
Tax Life = Book	2.05	2.38	0.46	0.39	0.27	0.47	0.00	6.01
No Tax Credits	1.89	2.38	0.46	0.30	0.25	0.47	0.00	5.75
CWIP	1.89	2.38	0.46	0.31	0.26	0.47	0.00	5.77
Flow-Thru Taxes	2.08	2.38	0.46	0.27	0.25	0.47	0.00	5.90
No Fuel Adj. Clause	1.89	2.38	0.46	0.30	0.25	0.47	0.00	5.75

APPENDIX C: RELATIVE BARRIERS AND INCENTIVES

Table C.1
Comparison of Tax Effects on Renewables to Conventionals, Investor-Owned Utilities

(Difference in Levelized Cost Ratio from Average Conventional Cost Ratio)

Generating Type	Effect of Including All Taxes and Credits	Effect of Including Property Taxes	Effect of Including Input Taxes	Effect of Including State Income Taxes	Effect of Including Federal Taxes and Credits	Effect of Accelerated Depreciation	Effect of Fed Tax Credits
Average Conventional	1.194	1.085	1.064	1.005	1.028	0.965	1.000
Renewable – Avg. Conventional							
Biomass-Plantation	-0.220	0.000	0.010	-0.011	-0.174	0.007	-0.170
Biomass-Waste	-0.005	-0.006	-0.002	0.001	0.004	0.009	0.000
Geothermal	-0.030	0.029	0.008	-0.008	-0.050	-0.064	0.000
Hydro	0.207	0.155	0.007	0.002	0.009	-0.070	0.000
Solar-Photovoltaic	0.074	0.188	0.007	-0.014	-0.080	-0.153	0.000
Solar-Thermal	0.046	0.146	0.007	-0.013	-0.074	-0.133	0.000
Wind	-0.288	0.224	0.036	-0.034	-0.322	-0.155	-0.272

Source: Tables 5.1, 5.3

Positive values indicate greater barrier (or less incentive) to Renewables than to Conventionals. Negative values indicate greater incentive (or less barrier) to Renewables than to Conventionals.

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Table C.2
Comparison of Ratemaking Effects on Renewables to Conventionals, Investor-Owned Utilities
(Difference in Levelized Cost Ratio from Average Conventional Cost Ratio)

Generating Type	Effect of Not Including CWIP in Rate Base	Effect of Normalizing Taxes in Rate Base	Effect of Automatic Fuel Adjustments
Average Conventional	1.000	0.990	1.001
Renewable – Avg. Conventional			
Biomass-Plantation	-0.001	-0.012	-0.001
Biomass-Waste	-0.001	-0.011	-0.001
Geothermal	-0.001	-0.047	-0.001
Hydro	-0.004	-0.090	-0.001
Solar-Photovoltaic	0.000	-0.102	-0.001
Solar-Thermal	0.000	-0.089	-0.001
Wind	-0.001	-0.104	-0.001

Source: Table 5.2

Positive values indicate greater barrier (or less incentive) to Renewables than to Conventionals.
Negative values indicate greater incentive (or less barrier) to Renewables than to Conventionals.

Table C.3
Comparison of Tax Effects on Renewables to Conventionals, Nonutility Generators

(Difference in IRR Ratio from Average Conventional IRR Ratio)

Generating Type	Effect of Including All Taxes and Credits	Effect of Including Property Taxes	Effect of Includling Input Taxes	Effect of Includ-ing State Income Taxes	Effect of Including Federal Taxes and Credits	Effect of Including Alternative Minimum Tax
Average Conventional	0.607	0.815	0.851	0.991	0.937	0.957
Renewable – Avg. Conventional						
Biomass-Plantation	0.921	-0.006	-0.022	0.060	4.619	-0.272
Biomass-Waste	0.103	0.009	0.008	0.017	0.125	-0.183
Geothermal	0.218	-0.001	0.020	0.027	0.354	-0.210
Hydro	0.102	0.010	0.080	0.007	0.053	-0.049
Solar-Photovoltaic	0.291	-0.030	0.072	0.033	0.445	-0.248
Solar-Thermal	0.280	-0.029	0.063	0.033	0.441	-0.246
Wind	0.740	-0.065	0.030	0.064	2.644	-0.312

Source: Table 6.1

Positive values indicate greater incentive (or less barrier) to Renewables than to Conventionals. Negative values indicate greater barrier (or less incentive) to Renewables than to Conventionals.

Table C.4
Comparison of Tax Effects on Renewables to Conventionals, Nonutility Generators

(Difference in Change in IRR from Change in IRR for Avg. Conventionals)

Generating Type	Effect of Including All Taxes and Credits	Effect of Including Property Taxes	Effect of Includling Input Taxes	Effect of Includ-ing State Income Taxes	Effect of Including Federal Taxes and Credits	Effect of Including Alternative Minimum Tax
Average Conventional	-4.24%	-1.47%	-1.13%	-0.06%	-0.44%	-0.28%
Renewable – Avg. Conventional						
Biomass-Plantation	6.98%	-0.40%	-0.50%	0.44%	6.94%	-2.22%
Biomass-Waste	1.26%	-0.08%	-0.07%	0.12%	0.86%	-1.37%
Geothermal	2.69%	-0.20%	0.05%	0.18%	2.08%	-1.57%
Hydro	1.73%	0.18%	0.68%	0.05%	0.37%	-0.29%
Solar-Photovoltaic	3.41%	-0.53%	0.52%	0.23%	2.47%	-1.86%
Solar-Thermal	3.30%	-0.53%	0.44%	0.23%	2.46%	-1.85%
Wind	5.91%	-0.69%	0.25%	0.40%	5.12%	-2.03%

Source: Table 6.1

Positive values indicate greater incentive (or less barrier) to Renewables than to Conventionals. Negative values indicate greater barrier (or less incentive) to Renewables than to Conventionals.

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TAB 9

Regulations Under Section 32 of the Public Utility Holding Company Act of 1935

SUBCHAPTER T—REGULATIONS UNDER SECTION 32 OF THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

PART 365—FILING REQUIREMENTS AND MINISTERIAL PROCEDURES FOR PERSONS SEEKING EXEMPT WHOLESALE GENERATOR STATUS

AUTHORITY: 15 U.S.C. 79.

SOURCE: Order 550, 58 FR 8906, Feb. 18, 1993, unless otherwise noted.

§ 365.1 Purpose.

The purpose of part 365 is to implement section 32 of the Public Utility Holding Company Act of 1935, as added by section 711 of the Energy Policy Act of 1992.

§ 365.2 Definitions.

(a) For the purpose of this part terms will have the same meaning as defined in the Public Utility Holding Company Act of 1935, as amended by the Energy Policy Act of 1992, except as provided in paragraph (b) of this section.

(b) For the purpose of this part:

(1) *Commission* means the Federal Energy Regulatory Commission; and

(2) *Receipt of an application* means the date that the Commission receives the application and the applicable filing fee, if any; and

(3) *Affected State commission* means the State commission of each state in which a generating facility owned and/or operated by the applicant is located; each State commission regulating the retail rates of an electric utility that will purchase power from the applicant, if known at the time of application; and, each State commission regulating a retail utility that is affiliated with the applicant.

§ 365.3 Contents of application and procedure for filing.

(a) A person seeking status as an exempt wholesale generator (applicant) must file with the Commission, and serve on the Securities and Exchange Commission and any affected State commission, the following:

(1) A sworn statement, by a representative legally authorized to bind the applicant, attesting to any facts or representations presented to demonstrate eligibility for EWG status, including:

(i) A representation that the applicant is engaged directly, or indirectly through one or more affiliates as defined in section 2(a)(11)(B) of the Public Utility Holding Company Act of 1935, and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale;

(ii) Any exceptions for foreign sales of power at retail; and

(iii) If the applicant intends to satisfy the "and selling electric energy at wholesale" requirement of paragraph (a)(1)(i) as a person engaged exclusively in operating all or part of one or more eligible facilities, a representation that the operator has an agency relationship with the person (or persons) who sells electric energy at wholesale from the eligible facility (or facilities).

(2) A brief description of the facility or facilities which are or will be eligible facilities owned and/or operated by the applicant including:

(i) The related transmission interconnection components;

(ii) Any lease arrangements involving the facilities, including leases to one or more public utility companies; and

(iii) Any electric utility company that is an affiliate company or associate company of the applicant.

(b) If a rate or charge for, or in connection with, the construction of a facility described in paragraph (a)(2) of this section, or for electric energy produced by a facility described in paragraph (a)(2) of this section (other than

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any portion of a rate or charge which represents recovery of the cost of a wholesale rate or charge), was in effect under the laws of any State on October 24, 1992, or if any portion of a facility described in paragraph (a)(2) of this section is owned or operated by an electric utility company that is an affiliate or associate company of the applicant, the applicant must also file a copy of a specific determination from every State commission having jurisdiction over any such rate or charge, or if the rate or charge is a rate or charge of an affiliate of a registered holding company, a specific determination from every State commission having jurisdiction over the retail rates and charges of the affiliates of the registered holding company, that allowing the facility to be an eligible facility:

(1) Will benefit consumers,

(2) Is in the public interest, and

(3) Does not violate State law.

(c) Applications for exempt wholesale generator status must also include a copy of a notice of the application suitable for publication in the FEDERAL REGISTER The notice must state the applicant's name, the date of the application, and a brief description of the applicant and the facility or facilities which are or will be eligible facilities owned and/or operated by the applicant. The applicant must also submit a copy of its notice on a 3½" diskette in ASCII format. Each diskette must be clearly marked with the name of the applicant and the words "notice of filing." The notice must be in the following form:

(Name of Applicant)
Docket No. EG–

Notice of Application for Commission Determination of Exempt Wholesale Generator Status

On (date application was filed), (name and address of applicant) filed with the Federal Energy Regulatory Commission an application for determination of exempt wholesale generator status pursuant to part 365 of the Commission's regulations.

[Brief description of the applicant and the facility or facilities which are or will be eligible facilities owned and/or operated by the applicant, including reference and citation to any applicable State commission determinations.]

Any person desiring to be heard concerning the application for exempt wholesale generator status should file a motion to intervene or comments with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with §§ 385.211 and 385.214 of the Commission's Rules of Practice and Procedure. The Commission will limit its consideration of comments to those that concern the adequacy or accuracy of the application. All such motions and comments should be filed on or before ______ and must be served on the applicant. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

[Order 550, 58 FR 8906, Feb. 18, 1993, as amended by Order 550-A, 58 FR 21255, Apr 20, 1993]

§ 365.4 Effect of filing.

A person applying in good faith for a Commission determination of exempt wholesale generator status will be deemed to be an exempt wholesale generator from the date of receipt of the application until the date of Commission action pursuant to § 365.5.

§ 365.5 Commission action.

If the Commission has not issued an order granting or denying an application within 60 days of receipt of the application, the application will be deemed to have been granted.

§ 365.6 Notification of Commission action to the Securities and Exchange Commission.

The Secretary of the Commission will notify the Securities and Exchange Commission whenever a person is determined to be an exempt wholesale generator.

§ 365.7 Procedure for notifying Commission of material change in facts.

If there is any material change in facts that may effect an EWG's eligibility for EWG status under section 32 of the Public Utility Holding Company Act of 1935, the EWG must within 60 days: apply for a new determination of EWG status; file a written explanation of why the material change in facts does not affect the EWG's status; or notify the Commission that it no longer seeks to maintain EWG status.

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United States - Federal

TAB 10

Transactional Finance Bulletin Published by McDermott, Will & Emery, October 6, 1992

TRANSACTIONAL FINANCE

BULLETIN

October 16, 1992

ENERGY POLICY ACT OF 1992 — PUHCA AND ELECTRIC TRANSMISSION PROVISIONS

Last week, Congress approved the Energy Policy Act of 1992, H.R. 776 (the "Energy Bill" or the "Bill"). The Bill creates a new class of wholesale-only electric generators — "exempt wholesale generators" (EWGs) — which are exempt from the Public Utility Holding Company Act (PUHCA). If signed into law by President Bush as anticipated, the Energy Bill will dramatically enhance competition in U.S. wholesale electric generation markets, including broader participation by subsidiaries of electric utilities and holding companies. The Bill will also open up foreign markets by exempting companies from PUHCA with respect to retail sales as well as wholesale sales.

Under the Bill, EWG status can only be obtained from FERC, on a case-by-case basis, and not from the SEC. Since FERC retains jurisdiction under the Federal Power Act (FPA) over the rates and certain financial transactions of EWGs, the Bill effectively centralizes regulation of EWGs at FERC. However, states must approve EWGs consisting of wholly or partially rate-based assets and EWG sales to utility affiliates, as well as the prudency of utility purchases of wholesale power. (The SEC maintains certain jurisdiction over registered holding companies [RHCs] and non-EWGs.)

Unlike "qualifying facilities" (QFs) under the Public Utility Regulatory Policies Act (PURPA), which partially deregulated the generation sector, EWG status will not be subject to restrictions relating to type of fuel, maximum size, technology or permissible utility ownership. EWGs will remain subject to regulation of wholesale power rates by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act (FPA) and to state regulation, as further discussed below. However, the PUHCA exemption will enable EWGs to obtain project financing without the necessity for sponsors to relinquish control in order to avoid PUHCA's regulation of upstream owners.

The Bill's implementation will be affected by a series of federal and state agency proceedings, although EWG transactions can and will proceed in the interim. Assuming the Bill is enacted into law, FERC is expected to promptly initiate rulemakings regarding eligibility for EWG status, transmission access and "full cost" transmission pricing. States will consider the competitive, financial and reliability impacts of purchased power from EWGs and other suppliers on state-regulated utilities and procedures for pre-approval of purchased power. And the SEC will initiate rulemakings on RHC investments in EWGs and foreign utility companies.

PUHCA Reform Provisions

(1) *"ELIGIBLE FACILITIES"*

An EWG must be engaged directly or indirectly through affiliates exclusively in the ownership and/or operation of "eligible facilities". An "eligible facility" is an electric generation facility whose output is sold only at wholesale. Except for "hybrid" facilities (described below), any sale of electric output at retail would vitiate EWG status. In contrast, QFs (and foreign utility companies — see below) can sell at retail and be exempt from PUHCA, although they may be subject to applicable state utility law.

(a) LEASES. An "eligible facility" also includes a facility which is leased to a public utility. However, a lease by an EWG is treated as a sale of electricity for purposes of FERC rate regulation under the FPA and thus must be approved by FERC as "just and reasonable," as must rates for wholesale sales of electricity by EWGs. The lease provision presumably does not, however, alter the ability of "passive" financing lessors to escape either PUHCA or FERC regulation under existing law, but is intended to prevent circumvention of FERC rate jurisdiction by leases which are in essence sales of electricity.

(b) RATE-BASED FACILITIES AND HYBRIDS. State commission approval is required if the facility was included in rate-base as of the date of enactment. A "hybrid" facility — owned in part by an "affiliate" or "associate company" (as defined in PUHCA) which is a public utility under PUHCA and in part by a non-utility — may also be an EWG with state commission approval. The Bill thus gives states power to block utilities from selling existing ratebase generation assets or spinning-off such assets into separate non-regulated EWG subsidiaries (*cf.* the CMS Midland repowering project, a QF but the subject of state commission opposition).

(2) *OBTAINING EWG STATUS*

EWG status can only be obtained on the basis of a FERC order issued on a case-by-case basis. FERC is to issue implementing regulations within 12 months but may act by order in the interim. (It is likely that FERC will enact rules permitting EWG and market-based rate approvals to be obtained in a single proceeding.) FERC may approve EWG status for facilities regardless of whether construction has commenced or been completed. Thus, as in the case of QFs, confirmation of EWG status prior to commencement of construction can be obtained. Also, non-QFs presently in construction or operation can obtain EWG status.

The Bill imposes a relatively tight deadline for FERC action to confirm EWG status — FERC must act within 60 days of the date an application is deemed to be complete — and further provides that a person filing an application for EWG in good faith is deemed to be an EWG until FERC acts. Together, these provisions enable parties to pursue EWG projects without undue regulatory delay or uncertainty. (Note that under FERC precedent an application is not "deemed complete" until all information requested by FERC has been received.)

(3) *UTILITY PARTICIPATION*

Electric utility companies and companies which are exempt holding companies or registered holding companies (RHCs) under PUHCA may own up to 100% of EWGs, wherever located. The Bill thus provides for substantial utility involvement in the wholesale power industry, subject to certain restrictions on utility asset spin-offs (discussed above) and RHC financings and contracts and affiliate transactions (below).

(a) <u>IMPACTS ON PURPA UTILITY OWNERSHIP TEST.</u> No change is made to the PURPA QF utility ownership limitation. However, the Bill provides that EWG ownership does not constitute utility ownership for purposes of the 50% limit, although an EWG will be an "electric utility" under the FPA.

(b) <u>RESIDUAL SEC JURISDICTION OVER RHCS.</u> Companies which are exempt holding companies may own EWGs without restriction under PUHCA. RHCs do not need SEC approval to acquire or own interests in EWGs. However, RHCs' sales of securities to finance EWGs or guarantees of EWG securities, as well as any contractual relationship with EWGs, require prior SEC approval. Under the Bill, such approval is to be granted regardless of where the EWG is located and without consideration of whether the investment is "incidental" to the RHC's public utility business, unless the SEC finds that an EWG investment would have a "substantial adverse effect" on the RHC system's financial integrity (as further defined in the Bill). The SEC must make such a finding, in the case of such sales or guarantees of securities, within 120 days of filing of a declaration with the SEC, and is to promulgate implementing rules within 6 months of the enactment date.

(c) AFFILIATE SALES.

(i) ***State approval.*** The Bill generally prohibits electric utilities from purchasing from an affiliated EWG, but permits such purchases on the basis of case-by-case State approval. Such approval is required from each state commission with regulatory authority over the purchasing utility's retail rates. The state commission must find that it has sufficient access to information, books and records and that the transaction in the public interest. The specific findings required include whether the transaction would provide an unfair competitive advantage due to the affiliation.

Companies not subject to state retail rate regulation, such as many electric cooperatives and municipalities, may also purchase from affiliated EWGs unless the electricity is to be resold to an affiliate (in which case approval of the affiliate's state regulator, if any, is required). "Reciprocal arrangements" with non-affiliates (such as "daisy-chaining") intended to circumvent the provisions of the bill are also prohibited.

(ii) ***FERC rate approval.*** The fact that sales to affiliates may be permitted does not mean that the rates for such sales will be approved by FERC. The Bill specifically amends the FPA to provide that an EWG's rates are unlawful if FERC finds, after notice and opportunity for a hearing, that they reflect an "undue preference or advantage" received from an affiliated electric utility.

(4) STATE APPROVAL OF UTILITIES' WHOLESALE POWER PURCHASES

Under existing law, FERC has exclusive authority to set wholesale rates but states have authority over utilities' power planning decisions, in part through their authority to allow or deny recovery of associated costs in retail rates. Building on this authority, the Bill directs states to determine within one year of the enactment date whether to institute

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advance approval requirements for wholesale power purchases not only from EWGs, but also from QFs and other utility purchased power sources.

The relevant state proceedings will be critical to the future development of EWGs and QFs. States are to consider cost of capital and rate impacts of purchases of long-term wholesale power, as compared with utility construction of new facilities; whether EWGs' leveraged capital structure "threatens reliability or provides an unfair advantage for [EWGs] over" utilities; and whether to require reasonable assurance of fuel supply for wholesale power providers. Each of these issues could be troublesome for the EWG industry, depending on the outcome of the state proceedings. However, the formulation in the Bill is preferable to proposals which had been made to require certain debt/equity ratios or other mandatory restrictions. In addition, the one-year clock helps to insure that state approval standards will be established, and the relevant uncertainties resolved, within a reasonable time-frame.

(5) STATE ACCESS TO BOOKS AND RECORDS

The Bill give states authority, upon written order, to examine the books and records of electric utilities under its jurisdiction (a right most states have under existing law) but also to examine the books and records of any EWG selling to such utilities and any utility or holding company affiliate. States are not to disclose "trade secrets or sensitive commercial information". Such access is material to states' approval of affiliate purchases and wholesale power purchase decisions (above).

(6) PURPA IMPACTS

It is unlikely that QFs' mandatory utility purchase and interconnection obligations will continue to provide a competitive advantage for QFs over EWGs in today's wholesale power marketplace. States may be expected to accelerate the trend toward all-source bidding in the context of least cost planning, in which QFs and EWGs compete to be the lowest-cost bidder. Unless substantial credit is given, for example, to renewable fuels in the form of environmental adders, a QF has no inherent advantage in competing for long-term energy or capacity contracts.

In fact, EWGs will have certain competitive advantages in relation to QFs under PURPA. EWG status will not be restricted with respect to fuel, size, or technology. In contrast, PURPA requires use of biomass, renewable energy or waste as fuel for small power production facilities, contains maximum size limits for hydro and biomass-powered facilities, and effectively limits cogeneration facilities' size and technology by imposing minimum thermal use (operating) and fuel efficiency standards.

In addition, electric utilities and holding companies may own up to 100% of an EWG, whereas the 50% restriction on utility ownership of QFs is unchanged. Yet because EWGs, like QFs, will be exempt from PUHCA, they will generally be able to be project financed and the sponsors can retain control of the project without regard to PUHCA's restrictions on upstream ownership, financing and geographical integration of utility facilities.

EWGs will have certain disadvantages as well. As noted above, EWGs will not be entitled to the QF exemption from the Federal Power Act (FPA) and hence their rates and certain financing transactions will continue to be regulated by FERC. EWGs will also continue to be subject to any state utility laws applicable to wholesale generators' financing or organization, from which QFs are exempt. (However, FERC has streamlined its regulation of sales made at market-based rates and certain states, like Massachusetts, have waived or streamlined state regulation.)

Unlike EWGs, QFs will be able to make retail sales of electricity, subject to state law as to whether the sale subjects the seller to state utility regulation (the PURPA state law exemption does not apply to such sales). Thus dual wholesale-retail sales and certain niche fuel and technology strategies will be the principal province of QFs.

(7) FOREIGN UTILITY EXEMPTION

The Bill broadly exempts from PUHCA "foreign utility companies" — companies owning electric *or natural gas* facilities whether for wholesale *or retail* sales which do not involve U.S. consumers. Exempt holding companies and RHCs under PUHCA are specifically authorized to own such foreign utility companies, subject in the case of RHCs to SEC review of the financial impacts of such ownership on affiliates and ratepayers but excluding any geographic or diversification-related barrier. In the case of investment in foreign utility companies by affiliates of utilities or holding companies, however, states must certify to the SEC their ability to protect ratepayers from negative financial consequences unless a previous decision to this effect had been made. Public utility companies (*i.e.*, here, gas and electric utilities) are generally prohibited from pledging their credit to support investments by affiliates in foreign utility companies.

TRANSMISSION PROVISIONS

The Energy Bill provides FERC with broad authority to mandate transmission access, and thus has the potential to open up the interstate transmission grid to the new class of EWGs as well as others engaged in wholesale power transactions.

Under the Bill, any electric utility or any other person generating wholesale electric energy, may apply to FERC for an order requiring a utility to transmit such energy, including enlargement of relevant facilities. This language includes PURPA QFs in the scope of parties that can apply for such orders, contrary to recent FERC decisions interpreting the availability of transmission access in the context of utility mergers.

The predicate for an application for a mandatory transmission order is refusal of a request that the utility wheel on a voluntary basis. Utilities must provide a detailed explanation of any such refusal within 60 days of such a request. FERC is to promulgate rules within 1 year of the enactment date requiring annual information filings by transmitting utilities concerning potentially available transmission capacity and known constraints.

It is important to note that the Bill authorizes, but does not require, FERC to order wheeling in response to an application (although FERC clearly favors opening up the interstate grid to competition). FERC could not order wheeling if to do so would impair the transmitting utility's reliability of service. FERC is flatly prohibited from ordering wheeling to end users (retail wheeling) or wheeling to any entity other than a municipality, existing electric cooperative or Federal power marketing agency or a traditional retail utility — *i.e.*, an entity that has an obligation to provide service under state or local law.

The Bill opts for full costing of transmission service and express concern for native load ratepayers, while leaving resolution of what constitutes full cost in a particular case to specific FERC proceedings. FERC is to establish rates for mandated transmission which permit recovery of "all costs, . . . including . . . an appropriate share, if any, of legitimate, verifiable and economic costs, taking into account any benefits to the transmission system" and costs of facilities construction. Rates must not assign transmission costs to the utility's existing wholesale, retail and transmission customers (hence existing transmission customers would be protected).

For additional information (including a copy of the PUHCA and transmission provisions of the Bill) or to discuss particular issues, please call 202/887-8000 and ask to speak with a member of the Project Finance Group.

November 1992

United States - Federal

TAB 11

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LEGAL TRENDS AND STRATEGIC OPTIONS

TRANSACTIONAL FINANCE

S P E C I A L E N E R G Y A C T I S S U E

VOL. 4 NO. 3

NOVEMBER 1992

1992 Energy Legislation Creates Major New Opportunities

The Energy Policy Act of 1992 (the "Energy Act" or the "Act") introduces the most sweeping set of legislative changes in more than a decade regarding how the United States will meet its future energy requirements. Building in part upon the trailblazing regulatory framework created by the Public Utility Regulatory Policies Act of 1978 ("PURPA") the Act embraces several new deregulation and incentive approaches which promise to expand greatly the opportunities for development of independent electric generation.

The Act exempts a new class of wholesale-only generators — known as "exempt wholesale generators" or "EWGs" — from regulation under the Public Utility Holding Company Act ("PUHCA").

EWG status is *not* dependent upon meeting the definitional prerequisites to the PUHCA exemption granted to qualifying facilities ("QFs") under PURPA. PUHCA concerns under existing law have slowed the development of "IPPs," independent power projects which could not satisfy the QF requirements. By removing this regulatory hurdle, the new EWG classification — which will be conferred on a case-by-case basis by the Federal Energy Regulatory Commission (the "FERC") — should foster the development and financing of a wide array of independent power projects that could not satisfy the fuel, size, efficiency or ownership requirements for obtaining QF status under PURPA.

In particular, the Act should facilitate much broader participation in independent power generation by engineering companies, equipment suppliers and subsidiaries of utility companies and holding companies who will no longer be forced to relinquish control of a project in order to protect their upstream affiliates from PUHCA regulation.

The Act also extends PUHCA exemptions to foreign projects, whether classified as "exempt wholesale generators" or classified as "foreign utility corporations."

Subject to some qualifications, U.S. companies and citizens will now be able to own electric or natural gas facilities that are engaged in wholesale or retail sales outside the United States (or to own companies which themselves own such facilities) free from either PUHCA regulation or the necessity of utilizing complex and cumbersome ownership structures (sometimes referred to as "PUHCA-Pretzels") in order to avoid such regulation. This exemption eliminates a significant regulatory impediment that has chilled the otherwise keen interest of many U.S. companies in pursuing opportuni-

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INSIDE

McDERMOTT, WILL & EMERY

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ties in the burgeoning international independent power market.

The Act bestows broad new authority upon the FERC to mandate that wholesale electric generators be afforded wheeling access to utility transmission systems.

This potential expansion of wheeling access is available not only to EWGs but also (contrary to existing FERC decisions) to QFs. While the Act does not compel the FERC to require transmitting utilities to grant wheeling access to wholesale electric generators, the new authority to do so could significantly improve the independent generators' leverage in attempting to negotiate wheeling arrangements, will facilitate development of those generating projects whose most feasible siting lies outside the service territory of the purchasing utility, and should result in new opportunities for financing new transmission facilities in areas with constrained transmission capacity.

The Act encourages provision of conservation services and technologies.

The Act reflects a fundamental policy shift toward encouraging utility and customer investment in conservation programs. The ability of conservation and demand-side management service providers to obtain a market is enhanced by the mandate that each electric utility engage in "integrated resource planning," under which the direct and quantifiable costs of all supply and demand measures (calculated on a life-cycle basis) are to be compared for the purpose of establishing the optimal plan for meeting customer requirements.

The Act also addresses a historical disincentive to utility conservation plans; for purposes of setting rates, utilities are allowed to make the same profit on their energy savings as would be achieved through energy facility investment. In addition, the Act established a broad range of building, residential, and governmental facility conservation standards and authorizes use of innovative financing techniques.

The Act establishes major new regulatory exemptions for U.S. and international independent power projects, expands wheeling access, and promotes pursuit of conservation, alternative fuels and new technology projects.

The Act employs a host of tax incentives to encourage investment in alternate fuels and innovative energy technologies, specifically encouraging investment in solar, geothermal, wind, and closed-loop biomass projects.

These regulatory and financing initiatives are discussed below, with particular emphasis on the financing structures and legal strategies necessary to achieve these business opportunities (and the regulatory hurdles which, in a few cases, must be overcome for these opportunities to be achieved).

If you have any questions concerning the Act, or our analyses of it, please contact any member of the practice. For telephone numbers and contact names, please see page 12 of this newsletter.

McDermott, Will & Emery
Energy and Utility Practice

International Project Opportunities

The Energy Act promotes U.S. investment in foreign utility operations by removing regulatory barriers that discouraged such investment. Prior to the Act, U.S. companies could not set up subsidiaries overseas to generate electricity for sale to foreign utilities or purchase interests in foreign electric or gas utilities without being considered "holding companies" under PUHCA. PUHCA holding companies include companies which own 10 percent or greater interests in electric utility companies, which generate, transmit or distribute electricity, or gas utility companies, which distribute natural gas for heat, light or power. Only foreign utility holding companies with no U.S. utility operations or subsidiaries were eligible for exemption from PUHCA without the necessity for any Secrities and Exchange Commission ("SEC") action or confirmation. (PURPA exempts from PUHCA only QFs located within the United States.) Registered holding companies ("RHCs") with significant multi-state operations, and to a lesser extent, exempt holding companies ("EHCs") with operations essentially confined to a single state, faced potential challenges to their foreign utility investments by the SEC and/or intervenors in SEC proceedings.

The Act largely removes PUHCA

restrictions on foreign utility ownership, in two ways. The EWG exemption applies to wholesale and retail generation and sale of electricity overseas. The Act also creates a new "foreign utility company" exemption which exempts from PUHCA foreign transmission and distribution of electricity and distribution of natural gas.

Owners and operators of foreign electric generating facilities are eligible for EWG status. To qualify for foreign EWG status, the technical requirements for EWG status must be met, except that foreign EWG status is not affected by retail sales of electricity generated by a foreign EWG. (A U.S. generator selling at retail, in contrast, would lose its EWG status.)

To qualify for EWG status, the owner and/or operator of a foreign generation facility must make a filing with FERC pursuant to the Act's amendments to PUHCA and EWG rules to be promulgated by FERC. However, the Act's restrictions on affiliate sales by EWGs and state consideration of purchased power issues should not affect foreign electric utility transactions, nor would FERC have jurisdiction under the Federal Power Act over a foreign EWG's rates. RHCs, however, must obtain SEC approval for any sales of securities to finance a foreign EWG, any guarantee of foreign EWGs' securities and any contractual relationship with a foreign EWG, in the same manner as for domestic EWG investments (*i.e.*, such approval is to be granted unless the EWG investment would have a "substantial adverse effect" on the financial integrity of the holding company system).

The Act also adds a new provision to PUHCA, exempting from PUHCA any "foreign utility company" subject to a requirement for state certification if the investor is a non-RHC utility affiliate and to certain SEC oversight if the investor is an RHC. A "foreign utility company" would include any company which owns electric transmission and distribution (T&D) systems or retail gas distribution systems, as well as any company which generates electricity.

A "foreign utility company" may not derive any income, directly or indirectly, from U.S. utility operations, nor may it be a U.S. public utility company. However, it may be a subsidiary or affiliate of a U.S. holding company or public utility company. The Act imposes no restriction on the percentage ownership of a foreign utility company which may be held by a public utility or a holding company.

The Act adds a new provision to PUHCA exempting from PUHCA any "foreign utility company," subject to a requirement for state certification if the investor is a non-RHC utility affiliate.

The Act does address the possible impact of foreign utility investments on U.S. utilities and ratepayers by imposing certain conditions on "foreign utility company" status for utility affiliates. Each state with regulatory jurisdiction over the retail rates of any public utility company (gas or electric) affiliated with a would-be foreign utility company or in the same holding company system (other than an affiliate of, or a company in a RHC system) must first certify to the SEC that the state has the "authority and resources to protect ratepayers, and intends to use that authority." The certification requirement is deemed to be satisfied by existing state determinations that ratepayers are sufficiently insulated from diversification and that diversification would not impair effective regulation. The certification may be withdrawn or modified but only prospectively, with respect to future investments. There is no time period within which states must provide a certification to the SEC; thus, delays in satisfying this requirement may be experienced unless the state has an existing diversification policy.

Unlike EHCs (whose operations are generally confined to a particular state), RHCs typically have operations in two or more states; hence Congress decided to maintain federal oversight of RHCs. The state certification requirement does not apply, but instead, the SEC is to promulgate rules regarding such acquisitions providing for "protection" of the customers of any public utility in the same holding company system and the "maintenance of the financial integrity" of the RHC. RHCs are expressly permitted to acquire and hold investments in one or more foreign utility companies without obtaining SEC approval. However, RHCs will require SEC approval for issuances of securities to finance acquisition of foreign utilities, guarantee of securities of a foreign utility or entry into contracts (except as prior law or the EWG exemption may otherwise exempt such transactions).

To summarize, international investments by U.S. companies, including utilities, can be projected to increase significantly in the wake of the Act. However, state and SEC implementation proceedings will affect the ability of utilities to penetrate this market.

ROGER B. WAGNER

Demand-Side Activities

While demand-side management receives less attention in the Energy Act than supply-side measures, potentially important suggested and mandated policies are included. The degree of implementation will be critical to their effectiveness and the extent to which they present opportunities.

The Energy Act "suggests" that states and their jurisdictional electric utilities follow certain courses of action in relation to promoting demand-side activities. The Act accomplishes this by amending PURPA. Out of deference to state commissions' authority to regulate their utilities, the Act does not mandate that its suggestions be followed. A public utility commission must hold a public hearing and state why it will implement or not implement the Act's suggestions. States that already have such standards in effect need not repeat their support for the standards. Therefore, the recommendations are targeted at states that have yet to adopt demand-side management policies similar to the ones being promoted by the Act. The activities to be considered include:

- That utilities and public utility commissions consider requiring integrated resource planning that compares supply and demand-side options on a systematic and comparable basis;
- that cost recovery for demand-side programs and measures make them at least as profitable for utilities as supply-side measures; and
- that there be rate changes that encourage investments in demand-side measures in generation, transmission and distribution of power. [Conference Report, Energy Policy Act of 1992, pp. 381-382].

Attention is paid to protecting small businesses engaged in demand-side services from the economic and organizational power of public utilities. Consumer concerns are addressed by stating that demand-side activities not increase the cost of electricity beyond what it would have been without such activities. Lastly, public utilities' interests are protected by the lack of any mandated procedures and Congress' hope that state commissions permit a fair rate of return on utility investments in demand-side activities.

The Act's main thrust with respect to federal agency energy management is to amend the National Energy Conservation Policy Act ("NECPA") by replacing certain goals within that act with what are now requirements. By the year 2005, all federal buildings are to have installed "all energy and water conservation measures with pay-back periods of less than ten years". Within 18 months after enactment, the Department of Energy ("DOE") must develop the procedures and methods used by all federal agencies to achieve the requirements. A federal energy efficiency fund under the control of DOE will assist all federal agencies in meeting the requirements. Significantly, all federal agencies are authorized and encouraged to participate in utility-sponsored demand-side management activities and programs. An amount equal to 50 percent of any energy and water cost savings realized by the agency in any fiscal year beginning after FY '92 shall be set aside by the agency to fund future demand-side management activities. Also, DOE will establish a financial bonus program to reward outstanding federal energy managers in all federal agencies and the United States Postal Service.

While this issue of *Transactional Finance* covers major opportunity areas and issues under the Energy Policy Act, necessarily it cannot be comprehensive. Key additional areas you may desire information on include:

- ***Hydroelectric Energy***
- ***Nuclear Power***
- ***Federal Buildings***
- ***International Opportunities***
- ***Industrial Power Strategies***

Attorneys in the practice have specific knowledge in each of these fields. For referral to appropriate attorneys in these or other areas of interest, please contact Roger D. Feldman (202) 778-8189.

NECPA is also amended to permit federal agencies to engage in demand-side performance contracts (provided that annual energy audits are satisfactory) and to provide that aggregate annual payments by a federal agency to either utilities or energy savings contractors may not exceed the amount that the agency would otherwise have paid for the energy.

Any federal agency may enter into a contract for a term of up to 25 years and may incur obligations pursuant to such contract to finance the demand-side management measures installed by the utility/energy savings contractor ("ESCO"). Within six months of enactment, the Office of Federal Procurement Policy shall establish the procedures and methods for use by federal agencies to select, monitor and terminate contracts with ESCO's so as to achieve the goals of the Act. Each agency will choose from a list prepared by the DOE unless an agency elects to develop its own list of qualified ESCO's.

By the year 2005, all federal buildings are to have installed "all energy and water conservation measures with pay-back periods of less than ten years."

Each agency will be empowered to select firms from these lists and also accept receipt of unsolicited proposals for energy-savings performance contracting following public notice. Once it does so, competitors may counter the proposal.

The Act places considerable emphasis on achieving the energy savings promised to the federal agencies. The Comptroller General of the United States shall report annually for a five-year period following enactment on the quality of energy audits conducted for federal agencies. With respect to energy savings performance contracts, mechanisms are to be established for inter-governmental energy management planning and coordination, including regional conferences led by the General Services Administration and DOE. Provision is also made for audits to assess accurate energy consumption for all buildings or facilities which any agency owns or operates or where the federal government leases the facilities.

JOHN F. SMITKA, JR.

Becoming an EWG — Mechanics and Choices

The Energy Act creates a new form of ownership structure for exempt wholesale generators. EWGs will have distinct advantages and disadvantages relative to the existing ownership structures of QFs under PURPA and IPPs. These advantages and disadvantages must be well understood by developers, lenders and other project participants. This article describes some of the more significant features of EWGs, including:

(i) qualification as an EWG;

(ii) permissibility of the form of transaction contemplated;

(iii) delineation of legal rights and exemption from regulation; and

(iv) preservation of legal rights in the event of change of facts supporting initial grant of status. It also briefly analyzes some of the financing related consequences of EWG status.

ELIGIBILITY FOR EWG STATUS.

The Act defines an EWG as "any person determined by the Federal Energy Regulatory Commission to be engaged directly or indirectly through one or more affiliates . . . exclusively in the business of owning or operating, all or part of one or more eligible facilities and selling electric energy at wholesale." "Eligible facilities" are defined to include those facilities which are exclusively used for generation of power for wholesale sales, or are leased to public utilities, and necessary interconnection facilities. Powerplants previously operated by utilities as rate-based facilities subject to state retail regulation may qualify as eligible facilities only with a determination by all applicable state commissions that specified public interest tests have been met. A facility jointly owned by an EWG and an affiliated utility (a "hybrid facility") cannot be an exempt facility unless similar determinations have been made by the state regulatory commission.

The Act directs the FERC to make a determination of an entity's EWG status within 60 days of application, during which period the facility is deemed to enjoy the status. FERC implementation rules to govern this process are required. They presumably will include further guidance as to characteristics of eligible facilities, although a review of the Notice of Proposed Rulemaking indicates that FERC views its role as a ministerial one in this regard.

EWGs' rights differ from those of QFs in many respects. The Act provides a carve-out from the PUHCA

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definition of "electric utility company" for entities which directly or indirectly are engaged exclusively in the business of owning all or part of "eligible facilities" and selling wholesale electric power. Consequently, like QFs, EWG's are exempt from all provisions of PUHCA, and ownership, control or operation of EWGs does not subject EWG owners or operators to SEC jurisdiction under PUHCA. EHCs and RHCs are free to own EWGs. RHCs, however, require SEC approval to issue securities in connection with the acquisition of an EWG and other transactions involving EWGs.

PERMISSIBLE TRANSACTIONS. Even if an entity is determined to have EWG status, certain of its transactions will remain subject to regulation. EWGs are FERC jurisdictional entities, and, as such, are subject to FERC public interest based determinations on the issuance of securities and certain corporate transactions. FERC has been flexible in its application of these regulations to IPPs. It is not certain

Tax Opportunities Under the Energy Act

The Energy Act contains several provisions that may induce taxpayers to make new investments in energy-related projects. These tax incentives will be attractive to potential investors in project partnerships or potential lessors.

The first provision is a permanent extension of the investment tax credit for investment in solar and geothermal property. The section, which previously expired at the end of June, provides a 10 percent credit for investment in property that uses solar energy to generate heat, that heats, cools, or provides hot water to a structure, or that provides solar process heat, or that is used to produce, distribute, or use energy derived from a geothermal deposit.

The second provision is a new credit for production of energy from renewable sources. Unlike the credit for solar and geothermal property, the renewable energy credit is available for energy produced rather than for investment in equipment. The credit is equal to 1.5 cents for every kilowatt (Kwh) hour of electricity produced from a qualified facility during the 10-year period beginning on the date the facility is placed in service. The 1.5 cent credit amount is indexed for inflation.

A qualified facility is a facility that produces electricity from wind or "closed-loop biomass." Closed loop biomass is organic material planted exclusively for the purpose of producing electricity. The electricity must be sold to an unrelated person and must be produced in the United States (or a possession).

The amount of the credit is reduced to the extent the average power sales contract price per Kwh for the previous year for the same type of renewable energy exceeds 8 cents per Kwh (indexed for inflation). The reduction is computed by taking the excess over 8 cents, dividing it by 3 cents, and then multiplying the result by the amount of the credit otherwise available. The amount of the credit is also reduced where other subsidies, such as grants and tax-exempt bonds, are received by the project in that year.

The third incentive is the repeal of certain alternative minimum tax rules in the case of independent oil and gas producers and royalty owners. These rules, relating to percentage depletion and intangible drilling costs, were alleged to be disincentives to drilling of new wells by the independents.

Finally, a new provision allows tax exempt bonds to be issued to finance environmental enhancements to hydroelectric generating facilities. Environmental enhancements include facilities that protect or promote fisheries or other wildlife resources or that are recreational facilities or other improvements required by the terms of the federal license. The new provision requires that 80 percent of the bond proceeds be used to finance the environmental enhancement and that the facility be governmentally owned. Proceeds of the bonds are not subject to the state-wide volume cap.

These new provisions create the possibility for new investments in energy technology. Partnerships in or leases to energy projects — such as biomass, wind, geothermal, and solar projects — could provide investors with significant investment opportunities. While the tax world has changed since the old days of 8-to-1 write-offs, there nevertheless is potential to attract capital from investors seeking better returns than are now available in the capital markets.

GREGORY F. JENNER
JENNIFER BRITT GIANNATTASIO

whether FERC would provide similar treatment to EWGs. Moreover, the Federal Power Act still requires FERC to defer to states which have applicable law in these fields. Since EWGs are not QFs, states may also attempt to assert jurisdiction over EWGs. The Act does not exempt EWGs from state corporate regulation, and consequently there may be other circumstances where state regulation applicable to transactional or organizational matters may be found to attach. Some FERC clarification of state jurisdictional rights under the Act with respect to EWG transactions is desirable.

In addition, it is clear that the Act bars utility-EWG affiliate transactions (directly or on some form of indirect reciprocal basis) in the absence of receipt of specified state determinations as to, among other things, consumer benefit and no unfair competitor advantage. Consequently, when there are proposed shifts in EWG ownership, they must be analyzed both in terms of effect on EWG eligibility and continued compliance with applicable statutory requirements.

EXTENT OF REGULATORY EXEMPTION. While the Act exempts EWGs from PUHCA, it leaves them subject to FERC and state jurisdiction which would otherwise apply to a person engaged in electric transactions. The power sales rates of EWGs (and the terms of leases to utilities) will be regulated by FERC. As discussed above, EWGs will also be subject to FERC rules concerning corporate reorganization and securities issuance, including state rules where applicable.

Certain state powers are specified under the Act, in addition to those discussed above. For example, state regulatory commissions have approval rights with respect to securities issuances or guarantees by jurisdictional utilities for the purpose of financing ownership or operation of foreign utility companies, and the right to examine books and records of EWGs selling to state jurisdictional utilities and their affiliates.

The Act expressly provides that it shall not infringe state or local government jurisdiction with respect to environmental protection and facility siting. The Act also may result in an expansion of state jurisdiction with respect to EWGs and QFs as well, by virtue of the Act's amendment to PURPA (discussed in the next article). The Act authorizes the states to take actions with respect to the allowable capital structure of EWGs, notwithstanding any other provision of federal law. FERC guidance as to matters such as the extent of "grandfathering" of transactions and the extent of potential application to QFs would be beneficial.

The Act expressly provides that it shall not infringe state or local government jurisdiction with respect to environmental protection and facility siting.

EWG related financing documentation and legal opinions will have to establish firmly the extent to which exercise of state rights may interfere with the financing assumptions of proposed transactions. In addition, transactions must be structured to deal with the possibility that state findings under the new PURPA provisions may change from time to time, as they have in the avoided cost area.

PRESERVATION OF STATUS IN THE EVENT OF CHANGE. The foregoing highlights the need for financing documentation to deal with the potential that, subsequent to initial compliance with applicable FERC rules, the ownership of an EWG, the nature of the eligible facility it holds, the character of its other business, its power sales or other arrangements or applicable state standards could shift, with the consequence that the EWG may no longer be entitled to the regulatory benefits associated with EWG status. Were an EWG to lose its status, it would not be eligible for PUHCA exemption. Absent PUHCA exemption pursuant to the Act, the full range of SEC jurisdiction over securities transactions and intercorporate transactions under PUHCA would attach, with adverse impact on EWG owners. (Similarly, while a QF which lost its status as such possibly may be an EWG, the resulting change in regulatory status under the Federal Power Act and state law would be such that it too would need to be specifically addressed in financing documentation.) Definitive financing documentation to anticipate and deal with any shifts necessarily will have to await FERC rulemaking. From a financing standpoint, it will be important to establish the timing of when loss of EWG status may come into play; whether there is a definitive point in time until which EWG status is certain (as arguably exists under PURPA); and how any other subsequent shifts in the overall applicable regulatory environment can be handled.

CONCLUSIONS. Financial documentation of EWG transactions presents significant issues. FERC rules can go a long way toward clarifying these issues. Critical to making EWGs a viable alternative to QFs will be participation in the upcoming FERC and state proceedings with a view to clarifying the issues of project eligibility, transaction permissibility, regulatory exemption and status retention.

Roger D. Feldman
Sean P. McGuinness

PURPA Revisited: The Energy Act's Great Challenge

Fundamental modification of PURPA may be initiated by Section 712 of the Energy Act. The result could be harm to the competitiveness of independent power options, regardless of ownership sources. It is imperative to know why that could be the case; what the issues will be; and what will be necessary to address them effectively.

The Act amends PURPA to effectively require that within one year from its enactment each state regulatory authority must conduct a proceeding for "general evaluation" of certain specified issues, (also referred to in the section as "standards") and determination of how the standards will be implemented.

As a result of such evaluation, and "notwithstanding any other provision of federal law", broad remedial action may be taken by state commissions, including action with respect to the "allowable capital structure of exempt wholesale generators", when it is determined in the public interest to do so. State proceedings must be conducted in the same manner as the first round of PURPA proceedings.

Two of the "standards" are interlinked:

- How utility purchases of long term wholesale power (from whatever supply source) — rather than construction of new generation facilities — will affect utility cost of capital, and with what resultant retail rate impacts;

- Whether utility reliability will be threatened as a consequence of their supply by EWGs, or whether utilities will be subject to an "unfair advantage" in competition with EWGs, since EWGs use proportionally more debt in their "capital structure" than do utilities.

Two additional "standards" require state regulatory commission scrutiny of two finance-related operational aspects of wholesale power supply (again, from whatever supply source):

- Whether there should be advance approval of specific power supply purchases;

- Whether approval of power purchase should be conditioned on "reasonable" assurances of fuel supply "adequacy".

THE POSSIBLE CONSEQUENCES

Obviously, the future of IPPs could be directly affected by these proceedings. Some of the potential adverse results include the following:

- EWG capital structure could be subjected to a mandatory debt ceiling cap. (This was originally proposed in the Senate.)

- Rules imputing higher capital cost to competitive bid proposals from an IPP could be established as a result of the implicit impact on utility cost of capital. (This would follow along the lines of the approaches already taken by the rating agencies and propounded by utilities in proceedings.)

- Fuel supply and transport contracts coterminous with power sales agreements could become a prerequisite for acceptability of competitive bids from IPPs. (This has already begun to occur in some jurisdictions.)

- Prior regulatory commission approval of power sales agreements is traditionally important from the standpoint of mitigating the risk of denial of utility passthrough to its customers of the cost of purchased power. Prior approval may involve more frequent evaluation of the comparison of power purchases with the then-annual costs to the utility.

The pendency of the proceedings in any state could have a chilling effect on the ability to close the financing for projects currently in development and may also affect the ability to complete competitive bids and power contract negotiations. Issues posed by the imprecise language of the Act include:

- Vulnerability of QFs to state modification of PURPA avoided cost, power contracting, and competitive bid rules in connection with state evaluation of the standards;

- Grandfathering of existing power contracts, bid awards, and financing and transactional arrangements;

- Adequacy and enforceability of existing power procurements; and

- Feasibility of final FERC approval of rates for sales by an EWG pending finalization of capital structure and fuel supply rules by state regulatory authorities.

All sectors of the electric power industry must be concerned with these possibilities. Supply growth is jeopardized. Utility affiliate development strategies may be retarded. The feasibility of launching an EWG-based development strategy may be set back. Effective integrated resource planning through comparison of conservation and supply options will be delayed.

To avoid state commission gridlock, there must be submission of objective and detailed analysis, which rises above rhetorical posturing. Commissions must be assisted in sifting through what will inevitably be a plethora of submissions. The outlines of the issues to be considered already are discernible from testimony, articles and rating agency activity which has already occurred. The conflicting arguments are summarized briefly below, as a roadmap to where data and analysis must be conducted. The potential difficulties summarized above can be forestalled if precedent for constructive consensus can be established.

THE COST OF CAPITAL /RATE IMPACT DEBATE

The objective predicate for determining whether to constrain EWG capital structure (standard #2) is examination of the issue of whether increased purchases of power from IPPs will raise utility cost of capital, with resultant rate increases. The essence of the argument is two-fold. First, attention focuses on whether the IPP-utility power sales agreement represents a transfer of capacity cost recovery and plant performance risk to the host utility that is higher than if the utility were to build the needed capacity. Second, concern is raised whenever the capacity charge payment obligation increases a utility's fixed cost obligations. While the resultant payments may be treated for financial accounting purposes as operating costs, they are argued as having the same effect on cash flow as fixed charges. If the utility had constructed the facility itself, the increased "debt" and associated risk would have been offset in part by new equity, which is not true in the purchased power case.

Standard & Poors has begun to impute a certain percentage of the future present value of capacity payments of power sales agreements as debt, and to compute an adjusted leverage ratio which treats the related debt obligation as part of the total debt. The resultant deterioration of a utility's debt/equity ratio over time can ultimately lead to reduction of the utility's bond rating, and increase in its cost of debt funds. The down-rating of several utilities during the past year has been attributed to excessive reliance on purchased power. Some utilities have sought limits on the amount of purchased power, or have claimed a premium value for purchased power, out of stated concern with this possible result.

Another adverse impact of purchased power arguably may be to reduce the return on and increase the cost of utility equity. Rate base erosion resulting from purchased power reliance can reduce rate-based generated revenue and earnings growth. It is also argued that rate-base erosion may leave a utility with less invested capital over which to spread risk, including the risk said to be shifted by the IPP through the project finance process. In this frame of reference, the only certain way to offset risk is to increase equity, with attendant cost to the utility. In turn, this type of analysis has led to the recommendation, which has not yet been accepted outright in any state proceeding, that utilities need to adjust IPP bids to reflect the effect of purchase on their cost of capital.

Section 712 of the Act can have a very adverse effect on IPPs if state regulatory commissions interpret it as the basis for restrictive standards.

IPPs challenge the characterization of risk shifting from IPPs to utilities, and also contest the resulting characterization of power contract risks as capitalizable debt risks. The use of the perceived leveraged IPP structure risk can be mitigated through power purchase acquisition strategies, and efficient use of competitive bidding. Construction risk is in fact shifted from utilities to third parties via turnkey contract arrangements. The current IPP operating record is such that it cannot be said to be a major risk. Regulatory risk falls upon utilities as well as IPPs. Utilities have a history of being plagued by prudence proceedings. They have not experienced any disallowances of purchased power, and the competitive framework in which IPP power is procured reduces the likelihood regulatory disallowance. From a utility operational standpoint, reliance on IPP power should not affect utility cost of capital.

Analysis of the actual structure of power sales arrangements argues against their characterization as a financial risk as well. The vast majority of contracts are take and pay, are subject to cancellation for non-performance or significant capacity derating, and frequently are dispatchable or curtailable.

Most fundamentally, what would the utility do in the absence of purchased power? The effect on utility financial condition of the additional financial burden that would be imposed in the absence of purchased power is the key to this issue. Purchases from wholesale suppliers, with preapproved passthrough, may be preferable to utility construction, with frequent prudence proceeding.

Finally, overall, it has not been demonstrated that, taken by itself, debt equivalence arising from power sales arguments, and prudently regulated power purchases, are themselves key factors, near term, affecting utility rates. As rate base erosion, and related fundamental structuring issues become more important, this scenario may change.

EFFECTS OF EWG LEVERAGE

The historical record shows that highly leveraged IPPs can be

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counted upon to maintain the same continuing quality of service as utility-owned facilities. Project finance loan covenants have the further effect of mitigating the key components of reliability risk, finance, fuel and environment.

For example, lenders not only review construction agreements to assure they will be kept whole in the event of a deficiency, but arrange for developer commitment to monitor construction standards and obtain liquidated damages. Operating risk is particularly covered by conditions precedent in loan agreements regarding conversion from construction to permanent loan, covenants against operating risks and operator replacement rights. Operating shortfalls are addressed by cash infusion obligations to deal with unexpected cash shortfalls and scheduled periodic expenses. Special provisions are also included to prevent siphoning off of funds from the project via the mechanism of a tightly defined and controlled "waterfall," permitted investment limitations and restriction on cash withdrawal from the project.

Concern with adequate operating coverage is dealt with through debt service reserves and explicit maintenance covenants. Utility indentures likely will not be as plant specific as IPP project financing arrangements.

Regarding the unfair competitive advantage issue, it is pertinent to note that while project finance uses proportionately less equity and more (relatively lower cost) debt, each element has, however, a higher cost in a project financing. That reflects the maturity of that debt and the need to fund debt service reserves.

While IPPs initial debt/equity ratio is significantly higher than that of utilities, it runs off faster, with the result that, even taking IPP refinancing into account, the average debt level of an IOU is higher than that of an IPP. Second, the weighted after tax cost of capital of IPPs only appears to be less than utilities if there is a failure to acknowledge the impact on IPP debt of its shorter term and the cost of carrying reserve funds.

There does not appear to be any generic advantage for either form of finance, when embedded cost, weighted average analysis is utilized. Indeed, project finance has a capital charge disadvantage compared to utility debt, because the markets have imposed a more rapid amortization schedule on it. This may be even truer if a marginal analysis is conducted, since during major multi-year construction cycles, debt financing is sometimes used to reduce equity. The alleged unfair advantage is not present.

CONCLUSIONS

Section 712 of the Act can have a very adverse effect on IPPs if state regulatory commissions interpret it as the basis for restrictive standards. Such restrictive concerns are not necessary to provide desired consumer protection. This absence of need for restrictions is due to:

- The improved risk sharing profile which utilities face as a result of IPP purchases;
- The numerous and fine-tuned covenants lenders impose on IPPs;
- The absence of the need to treat as debt power contract capacity credits; and
- The absence of an objective weighted cost of capital gap between IPPs and utilities, when IPP capital costs (including those arising from short debt term) are taken into account.

These are not self evident arguments, and ones that are likely to be disputed. It is critical for these matters to be resolved expeditiously in state commission proceedings, because their continuing status as matters for analysis may delay or defer project development and utility purchases.

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Registered Holding Companies

The Energy Act significantly enhances the opportunity for RHCs to diversify by allowing them to make investments in foreign utility companies and exempt wholesale generators. Although the SEC had recently indicated in an order on the Southern Company's Long Nol Project that it was willing to allow RHCs to invest in foreign utilities, the Act significantly reduces hurdles under PUHCA for RHCs desirous of making such an investment. Similarly, although the Ocean State Project, in which subsidiaries of Eastern Utilities Associates and the New England Electric System are significant investors, demonstrates that it was possible for RHCs to invest in IPPs, the SEC's interpretation of PUHCA had placed very significant restrictions on those investments, one of the most significant of which was the requirement that an IPP investment had to meet the integration requirements of Section 11 of the Act.

The Act inserts two new sections to the Holding Company Act, namely, Section 32, Exempt Wholesale Generators, and Section 33, Treatment of Foreign Utilities, which open up these new investment opportunities for RHCs. Although the sections are similar in their approach to allowing diversification, they are not identical.

EXEMPTIONS UNDER SECTION 32 AND SECTION 33

The EWG or foreign utility which is owned by an RHC will not be subject to regulation as a subsidiary company. The practical significance of this will be that the subsidiary should not have to seek prior SEC approval for issuing securities and making investments and will not be subject to Section 11 integration requirements. Registered public utility holding companies may make investments in EWGs and foreign utilities without prior SEC approval. Nevertheless, if a registered holding company has to issue securities to effect or finance such an investment, the SEC continues to have jurisdiction over such an issuance of securities.

CONTINUING REGULATION

Both Section 32 and Section 33 allow the SEC to regulate intercompany transactions between EWGs and foreign utilities as well as the creation or maintenance of any relationship between an EWG or a foreign utility and a member of the holding company system.

Both Section 32 and Section 33 also require the SEC to evaluate and limit the financial risk posed by investments in EWG and foreign utilities to the other members of the holding company group in connection with certain jurisdictional transactions, although the two sections adopt different approaches to this particular issue.

Under Section 32(h)(3), the SEC can refuse to allow a holding company to issue securities which will be used to finance an EWG or to provide a guaranty with respect to an obligation of an EWG only if the issuance of such security or the provision of such a guaranty would have "a substantial adverse impact" on the financial integrity of the holding company system. Under Section 32(h)(4), in determining to approve transactions not involving an EWG, the SEC is required to ignore the capitalization or earnings of the EWG, unless the transaction, together with the effect of such capitalization and earnings, would have a substantial adverse impact on the financial integrity of the holding company system. The SEC is required to promulgate rules within six months, setting forth the procedures which the SEC will employ in reviewing transactions for compliance with Sections 32(h)(3) through (h)(5).

Under Section 33 (c) (1), the SEC is required to promulgate rules or regulations regarding the acquisition of foreign utilities which shall provide for the protection of customers of United States public utility subsidiaries of RHCs and the maintenance of the financial integrity of holding company systems.

Unlike Section 32, Section 33 makes no attempt to limit the scope of the SEC's review by limiting the SEC's oversight to instances in which the transaction will have a "substantial adverse impact." Section 33(c)(2) also expressly provides that the SEC shall reasonably and fully consider a state commission recommendation regarding the holding company's relationship to a foreign utility. Section 33(e) imposes certain reporting requirements on RHCs which make or have investments in foreign utilities.

CONCLUSION

The Act makes it possible for an RHC to make significant investments in EWGs and foreign utility companies. The SEC can only limit EWG investments if they will have a substantial adverse impact on the financial integrity of an RHC system.

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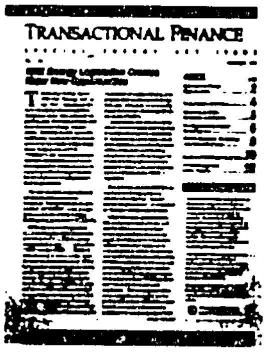
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TAB 12

Federal Energy Regulatory Commission Policy Statement Issued October 26, 1994 Regarding Pricing of Transmission Services

UNITED STATES-FEDERAL

- Federal Energy Regulatory Commission Policy Statement Issued October 26, 1994 Regarding Pricing of Transmission Services

680521

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Elizabeth Anne Moler, Chair;
Vicky A. Bailey, James J. Hoecker,
William L. Massey, and Donald F. Santa, Jr.

Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act	)))))	Docket No. RM93-19-000

POLICY STATEMENT

(Issued October 26, 1994)

The Federal Energy Regulatory Commission (Commission) announces a new policy regarding the pricing of transmission services provided by public utilities and transmitting utilities under the Federal Power Act (FPA). 1/ The new policy is designed to allow much greater transmission pricing flexibility than was allowed under previous Commission policies.

Greater pricing flexibility is appropriate in light of the significant competitive changes occurring in wholesale generation markets, and in light of our expanded wheeling authority under the Energy Policy Act of 1992 (EPAct). 2/ These recent events underscore the importance of ensuring that our transmission pricing policies promote economic efficiency, fairly compensate utilities for providing transmission services, reflect a reasonable allocation of transmission costs among transmission users, and

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1/ 16 U.S.C. §§ 824(e), 796(23).

2/ See 16 U.S.C. §§ 824j, 824k.

maintain the reliability of the transmission grid. The Commission also recognizes that advances in computer modeling techniques have made possible certain transmission pricing methods that once would have been impractical.

Based on the record developed in this proceeding, the Commission concludes that there appears to be a variety of workable, non-traditional transmission pricing methods that offer potential improvements in fairness, practicality and economic efficiency. For instance, the Commission believes that distance-sensitive rates using contract path or flow-based methods will be acceptable if properly supported.

Accordingly, the Commission will permit more flexibility to utilities to file innovative pricing proposals that meet the traditional revenue requirement and will allow such proposals to become effective 60 days after filing, 1/ as long as they satisfy certain pricing principles discussed below. We refer to this category of proposals as conforming proposals. We will also permit utilities to file pricing proposals that deviate from the traditional revenue requirement, as long as they meet certain requirements discussed below. We refer to these filings as non-conforming proposals. Non-conforming proposals will be permitted to go into effect only prospectively from the date the Commission determines that such a pricing proposal meets the statutory requirements of the FPA, i.e., is just and reasonable and not

1/ Whether to suspend such a filing and impose a refund condition will be decided on a case-by case basis. See West Texas Utilities Company, 18 FERC ¶ 61,189 (1982).

unduly discriminatory or preferential.

In addition to the guidance in this Policy Statement regarding conforming and non-conforming transmission pricing proposals, there are two specific subject areas for which we have instituted separate proceedings, and which may require transmission pricing flexibility. See Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, IV FERC Stats. & Regs. ¶ 32,507, 59 FR 35274 (July 11, 1994); Alternative Power Pooling Institutions under the Federal Power Act, Notice of Inquiry, FERC Stats. & Regs. ¶ ______ (1994). In those proceedings, we are examining what type of pricing policy is appropriate. We intend to examine whether any special procedural mechanisms are necessary to coordinate our pricing policy and filings proposing alternative power pooling institutions.

I. Introduction

The Commission will consider a broad range of rate design methods, within a utility's embedded original cost revenue requirement, as discussed in Section IV. We will also consider proposals that deviate from a utility's embedded original cost revenue requirement (subject to certain filing procedures and evaluation criteria), as discussed in Section V. The U.S. Supreme Court has recognized the Commission's broad latitude to fix rates. There is no single valid theory of ratemaking. Under the statutory standard of "just and reasonable" it is the result reached, not the method employed, which is controlling. Duquesne Light Co. v. Barasch, 488 U.S. 299, 316 (1989) (Duquesne); Federal Power

Commission v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944) (Hope). As the Court observed in Duquesne:

> The designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors.

488 U.S. at 316. Consistent with our broad ratemaking authority, in this Policy Statement we announce that we will consider various ratemaking methods to encourage proposals that will produce consumer benefits.

The Commission's traditional transmission pricing policy has permitted a public utility providing firm transmission service to charge rates designed to yield annual revenues equal to the rolled-in embedded cost 4/ of the utility's integrated transmission grid on a postage stamp basis (i.e., not distance sensitive), including the rolled-in costs of any new facilities or upgrades that become part of the integrated system. For non-firm transmission service, the Commission has permitted rates to reflect, in addition to the variable costs of providing the service, a charge up to a 100 percent contribution to the fixed costs of providing the service, with the proviso that pricing must reflect the characteristics of the service provided, e.g., the degree of interruptibility. Traditionally, transmission rates have been based on a "contract path" model, i.e., an assumed transmission path from point A to point B, that may or may not represent the actual flows of power on

4/ Embedded cost is generally viewed as including a fair rate of return on the original cost of facilities, less depreciation, plus operation and maintenance expenses, and taxes. Embedded costs are those costs reflected in the utility's books of account.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR PART 2

[Docket No. RM93-19-000]

Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act

POLICY STATEMENT

(Issued October 26, 1994)

AGENCY: Federal Energy Regulatory Commission

ACTION: Policy Statement

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing this policy statement to announce a general policy regarding the pricing of transmission services provided by public utilities and transmitting utilities under the Federal Power Act.

The new policy is designed to allow much greater transmission pricing flexibility than was allowed under previous Commission policies.

EFFECTIVE DATE: This policy statement is effective as of October 26, 1994.

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(technical issues)

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In recent years, the Commission attempted to address the industry's changing needs by modifying its historical transmission pricing policy 5/ to allow a type of incremental cost pricing. 6/ In order to provide new or expanded transmission service, a utility may be required to add expensive transmission assets, which can result in an increase in rolled-in embedded cost rates. To address this possibility, the Commission has allowed a utility to charge transmission-only customers the higher of embedded costs (for the system as expanded) or incremental expansion costs, but not the sum of the two. 7/ When the transmission grid is constrained and the utility chooses not to expand its system, the

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5/ See Northeast Utilities Service Company (Re: Public Service Company of New Hampshire), Opinion No. 364-A, 58 FERC ¶ 61,070, reh'g denied, Opinion No. 364-B, 59 FERC ¶ 61,042, order granting motion to vacate and dismissing request for rehearing, 59 FERC ¶ 61,089 (1992), affirmed in part and remanded in part sub nom. Northeast Utilities Service Company v. FERC, Nos. 92-1165, et al., 993 F.2d 937 (1st Cir. 1993), order on remand, 66 FERC ¶ 61,332, reh'g denied, 68 FERC ¶ 61,041 (1994), appeal pending No. 94-1949 (1st Cir. Sept. 6, 1994); Pennsylvania Electric Company, 58 FERC ¶ 61,278, reh'g denied and pricing policy clarified, 60 FERC ¶ 61,034, reh'g denied, 60 FERC ¶ 61,244 (1992), affirmed sub nom. Pennsylvania Electric Co. v. FERC, 11 F.3d 207 (D.C. Cir. 1993) (Penelec).

6/ Incremental cost is the cost of increasing the level of service provided. In practice, it typically refers to the cost of additional facilities needed to provide the requested service.

7/ This current pricing policy is based on three goals that the Commission adopted in the Northeast Utilities case: (1) to hold native load customers harmless, (2) to provide the lowest reasonable cost-based price to third-party firm transmission customers, and (3) to prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions.

Commission has allowed a utility to charge the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two. The opportunity costs, in turn, are capped by incremental expansion costs. This type of pricing has been referred to as "or" pricing or Northeast Utilities pricing. 8/ While "or" pricing will continue to be allowed under the Commission's pricing policy, the Commission is prepared to move beyond "or" pricing to consider other pricing alternatives.

II. Request for Comments

On June 30, 1993, the Commission issued a notice of technical conference and request for comments concerning these policies and other transmission pricing issues. Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, IV FERC Stats. & Regs., Notices ¶ 35,024 (1993) (Pricing Inquiry). The Commission received comments and reply comments from 165 entities, representing a broad cross-section of parties that participate in, or are affected by, the electric utility industry. The Commission also held technical conferences on April 8 and 15, 1994, that provided further opportunity for public comment and discussion. A summary of the comments received in this proceeding that included proposals for change is presented in Appendix A. 9/

Those commenting expressed a variety of opinions on many transmission pricing issues, including whether transmission rates

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8/ See supra note 5.

9/ Appendix A will not appear in the Code of Federal Regulations.

should reflect distance sensitivity and whether and how to compensate for flows over parallel paths. The commenters were nearly unanimous in their call for the Commission to provide further guidance concerning acceptable pricing methods. Some commenters indicated that such guidance would assist the formation of regional transmission groups (RTGs) by indicating what pricing policies will be acceptable to the Commission.

While many of the comments expressed dissatisfaction with the Commission's current pricing policy, the comments indicated no consensus for any one alternative pricing method. However, the commenters expressed general agreement that some type of transmission pricing reform by the Commission is needed. There was a strong consensus that such reform should: (1) allow greater pricing flexibility; (2) provide pricing that is "transparent" 10/ and easy to administer; (3) promote economic efficiency, that is, allow transmission customers to make informed decisions as to the economic consequences of their choices, and encourage transmission owners to make efficient use of, and investment in, the transmission grid; (4) ensure equity and fairness; and (5) facilitate the development of RTGs. 11/

10/ We interpret the commenters to mean that transmission pricing would be identified separately from generation pricing, that transmission pricing would identify all cost components of the transmission service (e.g., identify ancillary service costs) and that pricing information would be readily available to all bulk power participants.

11/ Two RTG agreements recently filed with the Commission postpone dealing with the transmission pricing issue by simply providing that pricing shall be consistent with the
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However, there was disagreement regarding the degree to which reform of transmission pricing should stress administrative simplicity versus accuracy. Some commenters advocated the continued use of traditional contract path and postage stamp rates, in part because these rates are simple to administer. Other commenters proposed methods, such as distance sensitive and flow-based rates, that may give better price signals but involve more complexity.

In response to the comments received, the Commission has decided to revise its policies to permit utilities much greater flexibility. We are prepared to accept a variety of pricing methods in addition to Northeast Utilities pricing. Northeast Utilities pricing will still be acceptable because it fully comports with the pricing principles we adopt today. However, based on the record developed herein, a variety of other pricing methods will also be acceptable.

The Commission concludes that greater pricing flexibility is now required for several reasons. First, exclusive use of methods that worked reasonably well in the past does not provide sufficient flexibility to accommodate the evolving needs of transmission owners and users in a more competitive era. 12/ It is important

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11/(...continued)
Commission's transmission pricing policy. See Pacificorp, et al. (on behalf of Western Regional Transmission Association), 69 FERC ¶ ________ (1994); Southwest Regional Transmission Association, 69 FERC ¶ ____) (1994).

12/ See American Electric Power Service Corporation, 67 FERC ¶ 61,168 at 61,490 (1994).

to gain practical experience with alternative transmission pricing approaches in order to assess how best to accommodate the current and future needs of the industry in providing efficient and reliable power supply as the industry becomes increasingly competitive. Second, our existing "or" pricing policy may not always encourage the most efficient investments in and use of the transmission grid. Third, regional differences (e.g., power flow patterns and population densities) justify a more flexible policy that can account for such differences. Fourth, a more flexible pricing policy may be necessary to implement effectively our RTG policy, which encourages RTGs to deal with a broad range of issues, including pricing, and which suggests that the Commission, in appropriate circumstances, will defer to RTG decision-making. 13/ The Commission is convinced that a more flexible pricing policy can help to achieve broader policy goals and be implemented in a manner that is just and reasonable and not unduly discriminatory or preferential.

In developing a more flexible transmission pricing policy, the Commission's basic premise is that comparable access to efficiently priced transmission services is critical to the continued development of a competitive wholesale power market. With this fundamental underpinning in mind, the Commission has developed several pricing principles that new pricing proposals should follow. Some of these principles reflect existing pricing

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13/ Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (Aug. 5, 1993), III FERC Stats. & Regs. ¶ 30,976 (July 30, 1993) (RTG Policy Statement).

requirements that any new proposal must continue to follow. Other principles, while important, may have to be balanced against one another.

Before discussing the pricing principles and specific new methodologies that may be acceptable, there are several points we would like to make. First, the Commission believes that improving price signals is an important goal, but recognizes that trade-offs between improved price signals and simplicity are inevitable. On one hand, transmission service is typically a small component of the total cost of electric service and, therefore, arguably does not merit overly complex pricing methods. 14/ On the other hand, in many cases transmission capacity is a scarce and valuable resource, and its pricing can send signals that promote the efficient siting of generation facilities and efficient decisions as to the dispatch of generation. In addition, new technological advances, particularly in computer technology, have made certain innovative pricing methodologies workable in practice. We therefore must balance the sometimes competing goals of better price signals and simplicity when evaluating any new pricing methodologies.

Second, the Commission also recognizes that it must move beyond certain precedent in order to entertain alternative pricing

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14/ Historically, transmission plant has represented less than 12 percent of total electric plant in service for major investor-owned Electric Utilities and generally less than six percent of the cost of electricity to end users. (Derived from cost data in 1992 Energy Information Administration Financial Statistics of Major Investor-Owned Electric Utilities.)

proposals. For example, instead of requiring a single postage stamp rate for transmission over the integrated transmission system of a corporation, such as a holding company system with several affiliated operating companies, 15/ we will now entertain proposals such as zonal rates 16/ that take distance within the corporation into account, provided that such proposals are consistent with the pricing principles that we adopt today. 17/ Having analyzed new methodologies presented in the record, we believe that some departures from our traditional integrated system pricing requirement will be supportable under the FPA if appropriately developed.

Third, as previously noted, several commenters urged the Commission to provide a framework for reforming pricing that would

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15/ See, e.g., Southern Company Services, 55 FERC ¶ 61,173 (1991), order on reh'g, 57 FERC ¶ 61,093 (1991), aff'd, Alabama Power Company v. FERC, 993 F.2d 1557 (D.C. Cir. 1993).

16/ Under zonal rates, a utility's facilities are divided (disaggregated) into a number of zones. The total cost assigned to any request for transmission service would depend on the number of zones traversed and the rate for each zone.

17/ If a utility, or public utility holding company system, proposes to disaggregate its integrated transmission system into distinct components (or zones) for purposes of developing transmission rates for third parties, it must apply the same approach consistently and uniformly across the entire system for all uses of the system, including its own uses.

We caution that any such zonal approach or other disaggregated approach would also need to appropriately recognize all flows on the system. For example, if flows are used to allocate costs on some lines, flows should be used to allocate costs for all remaining lines in the same way; e.g., it would not be acceptable to presume that each transmission customer proportionally uses and relies upon all remaining lines of the integrated system.

supplement the Commission's RTG Policy Statement. The Commission continues to believe that it would be appropriate for RTGs to address transmission pricing. We anticipate that the pricing flexibility provided herein, and our willingness to give appropriate deference to RTG decisions, will not only encourage the development of RTGs, but will also encourage RTGs to address transmission pricing, including regional issues affecting such pricing.

Finally, we do not want our policy to be so rigid that utilities will be prohibited from proposing pricing alternatives that may deviate from the traditional revenue requirement. Because transmission remains a natural monopoly, we believe it will be difficult for transmission owners to support such pricing under the FPA, particularly market-based transmission rates. However, we believe that it would be shortsighted to foreclose completely consideration of such non-conforming proposals. The electric utility industry of today is very different from the electric utility industry that existed only 20 years ago and even five years ago. Just as we today change our policies to reflect recent changes, we must remain flexible if we are to respond to future changes. Accordingly, we detail procedures and standards below that will be used in evaluating transmission pricing proposals that do not conform to the traditional revenue requirement.

We now turn to the requirements of the FPA and the pricing principles that we have developed consistent with those requirements.

III. Transmission Pricing Principles

Transmission pricing must adhere to the FPA requirement that transmission rates be just and reasonable and not unduly discriminatory or preferential. This requirement is found in sections 205, 206, and 212. In addition, section 212(a) requires that wholesale transmission rates for services ordered under section 211 must:

- permit the recovery of all costs incurred in connection with the transmission services and necessary associated services, including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities;
- promote the economically efficient transmission and generation of electricity; and
- to the extent practicable, ensure that costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for the 211 order and not from a transmitting utility's existing wholesale, retail, and transmission customers.

Consistent with these statutory requirements, which give the

Commission discretion in setting rates within the zone of reasonableness, and in light of the comments received in response to the Pricing Inquiry, we have formulated five principles that will guide our approval of pricing for both firm and non-firm transmission services in the future. The Commission believes these principles comport with the statutory requirements of sections 205, 206 and 212 of the FPA, and, in the interest of developing a uniform transmission pricing policy, we will apply these same principles to the pricing of transmission service whether that service is provided under section 205, 206, or 211 of the FPA.

The first two principles reflect fundamental requirements previously established by the Commission. A conforming proposal is one that meets the first principle, i.e., it proposes pricing that meets the traditional revenue requirement. A conforming proposal must also meet the second principle, i.e., it must reflect comparability. As to the other three principles, however, these reflect goals that an applicant with a conforming proposal must try to meet, but that ultimately may need to be balanced against one another in the Commission's determination of whether the proposed rates are just and reasonable.

A non-conforming proposal is one that does not meet the first principle, i.e., it does not propose pricing that meets the traditional revenue requirement. However, a non-conforming proposal must meet the second principle, i.e., it must reflect comparability. If a non-conforming proposal does not clearly demonstrate that the comparability requirement is met, it will be rejected. As to the remaining three principles, these reflect goals that an applicant with a non-conforming proposal must try to meet, but that may need to be balanced against one another. In addition, as part of its balancing, the Commission will consider the extent to which the first principle is not met. 18/

We discuss these principles in detail below.

1. Transmission Pricing Must Meet the Traditional Revenue Requirement

For conforming proposals, transmission prices must be based on the costs of the transmission service provided. The process of determining transmission prices involves three distinct steps. First, a utility must determine its total company revenue requirement, the capital component of which traditionally has been measured by embedded (depreciated original) cost. Second, a utility must allocate among individual customers or classes of customers that portion of the total revenue requirement that is attributable to providing transmission services, in a manner which appropriately reflects the costs of providing transmission service to such customers or classes of customers. Finally, the utility must design rates to recover those allocated costs from each customer class.

Different customers may pay different rates if they use the system in different ways. In the aggregate, however, rates are designed so that a transmission owner meets, but does not exceed,

18/ A pricing proposal that deviates from cost only slightly may be easier to justify than one that results in prices several times cost.

its revenue requirement. That is, it should be able to collect revenues from all its customers equal to the sum of its prudently incurred embedded costs, including return on capital.

There are two reasons for requiring transmission pricing to meet the traditional revenue requirement. First, it appears that transmission will remain a natural monopoly for the foreseeable future. It is unlikely that market-based prices for monopoly services, especially for firm transmission service, could be justified under the FPA at the present time, under the current industry structure. However, it is clear that there is no single appropriate ratemaking method under the FPA. The end result is the appropriate yardstick against which to measure the legality of a rate order, not the ratemaking method. Thus, although no single ratemaking method is necessarily favored by the FPA, this pricing principle will ensure that transmission users pay a just and reasonable price for transmission services and that transmission owners, while being appropriately and adequately compensated, 19/ will not be able to exercise their market power to collect exorbitant rates.

Second, we believe that pricing within an embedded cost revenue requirement provides adequate incentives for transmission owners to provide comparable transmission services, as long as the transmission owner has the opportunity for full cost recovery. When upgrades are required, the transmission owner may incur

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19/ Duquesne, 488 U.S. at 316; Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia, 262 U.S. 679 (1923); Hope, 320 U.S. at 602.

significant expenses related to planning and siting new facilities. For example, a utility may be required to pay for environmental mitigation associated with the construction of new transmission facilities. Such costs will be recoverable by the transmission owner if they are prudently incurred.

In addition, under the traditional revenue requirement principle, transmission owners clearly may, with appropriate support, 20/ recover the legitimate and verifiable costs of services they provide that are ancillary to transmission services, such as load following, reactive power compensation, and backup power services. However, transmission customers should also be permitted to provide these services themselves or to obtain them from someone else if this is feasible.

Finally, as discussed in Section IV below, we intend to allow significant latitude and a wide variety of non-traditional rate design proposals, within a cost cap based on the total company revenue requirement.

2. Transmission Pricing Must Reflect Comparability

Any new transmission pricing proposal, conforming or non-conforming, must meet the Commission's recently announced comparability standard. In American Electric Power Service Corporation (AEP), 67 FERC ¶ 61,168 (1994), the Commission articulated a new standard for judging whether access to transmission services is unduly discriminatory, or anticompetitive.

20/ See Northern States Power Company (Minnesota and Wisconsin) Opinion No. 383, 64 FERC ¶ 61,324 (1993), reh'g pending (reactive power).

The Commission noted that "[a]n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system." 21/ This principle has been applied to all open access tariffs filed since AEE, as well as to transmission services provided by RTGs. 22/

There is a relationship between price and quality of service (i.e., in general, higher quality service costs more). In Florida Municipal Power Agency v. Florida Power & Light Co., 67 FERC ¶ 61,167 at 61,482 (1994) (FMPA), the Commission stated, "[s]ince FMPA wants to be able to use the transmission system as freely as does Florida Power, it must pay a rate that reflects that equality." As a result of the relationship between quality of service and price discussed most recently in FMPA, and the growing importance of service comparability, we will require that pricing be comparable. Comparability of service applies to price as well as to terms and conditions. Comparability of transmission pricing involves a "golden rule of pricing" -- a transmission owner should charge itself on the same or comparable basis that it charges others for the same service. 23/

21/ 67 FERC at 61,490.

22/ See PacifiCorp, et al. (on behalf of Western Regional Transmission Association), 69 FERC at ______; Southwest Regional Transmission Association, 69 FERC at ______.

23/ There is a similar "golden rule of access" -- provide the same or comparable services to others as you provide yourself.

This golden rule has several implications. First, for purposes of setting FERC-jurisdictional rates, costs must be allocated between jurisdictional and non-jurisdictional customers in a consistent way, to determine the cost responsibility of the two sets of customers. 24/

Second, when a utility uses its own transmission system to make off-system sales, it should "pay" for transmission service at the same price that third-party customers pay for the same service, and credit the transmission revenues to its native load customers. This treatment restricts the transmission owner's ability to gain an unfair advantage in the bulk power market by selling itself transmission service at a discount that would be subsidized by native load and transmission-only customers. 25/

Pricing comparability does not mean that the Commission is endorsing an end result in which there are no differences in prices paid by various customers. For example, the Commission is not suggesting that prices must be based on highly aggregated costs so that all customers face a uniform rate per kWh of service. Rather,

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24/ The Commission is not in any way suggesting any interference with state authority to determine the appropriate ratemaking methodology for bundled retail sales.

25/ In PSI, for example, the Commission required that PSI take transmission service under its own transmission tariff when making market-based power sales. The Commission adopted this approach to prevent PSI from using its transmission ownership to exercise an unfair competitive advantage in wholesale power markets. Public Service Company of Indiana, Inc., Opinion No. 349, 51 FERC ¶ 61,367 at 62,201 (1990), order on rehearing, PSI Energy, Inc., 52 FERC ¶ 61, 260, order granting clarification, 53 FERC ¶ 61,131 (1990), appeal dismissed sub nom. Northern Indiana Public Service Co. v. FERC, 954 F.2d 736 (D.C. Cir. 1992).

we are receptive to pricing proposals that disaggregate costs in order to give better price signals to all users of the system -- third parties and the transmission owner itself. Such disaggregation still permits different customers to pay different prices. Pricing comparability does not rule out such a result.

Finally, comparability of pricing includes certainty of pricing. A transmission customer should have pricing certainty comparable to that of the transmitting utility, e.g., the same transmission pricing certainty for long-term power contracts as the transmitting utility has.

3. Transmission Pricing Should Promote Economic Efficiency

Section 212(a) of the FPA, as amended by EPAct, states that transmission pricing should promote economically efficient generation and transmission of electricity. 26/ In our view, this means that transmission pricing should promote good decision-making and foster:

- efficient expansion of transmission capacity;
- efficient location of new generators and new load;
- efficient use of existing transmission facilities, including the efficient allocation of constrained capacity through appropriate market clearing mechanisms; and
- efficient dispatch of existing generating resources.

To the extent practicable, transmission rates should be

26/ 16 U.S.C. § 824k(a).

designed to reflect marginal costs, 27/ rather than embedded costs, in a manner consistent with the remaining principles. We favor marginal cost prices in order to promote efficient decision-making by both transmission owners and users. 28/ In the short-run, marginal transmission costs are primarily line losses and, when lines are congested, opportunity costs. In the long-run, marginal transmission costs include all the costs of the transmission system and support services. The Commission recognizes the complexity of estimating marginal cost on the transmission grid and of implementing pricing that follows marginal transmission costs, but we encourage experimentation in this area. 29/ On a case-by-case basis, we will balance the desirability of more economically efficient price signals against the additional complexity of implementing such pricing.

4. Transmission Pricing Should Promote Fairness

As a general matter, transmission pricing should be fair and equitable. This has two important implications. First, the EPAct requires that, to the extent practicable, existing wholesale, retail and transmission customers should not pay for the costs incurred in providing wholesale transmission services ordered under

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27/ Alfred Kahn, infra n.28, defines marginal cost as "[t]he cost of producing one more unit; it can equally be envisioned as the cost that would be saved by producing one less unit."

28/ See 1 Alfred E. Kahn, The Economics of Regulation 63-86.

29/ Such proposals should be fully supported, with as much detail as possible. See New England Power Company, Opinion No. 352, 52 FERC ¶ 61,090 (1990), reh'g denied, Opinion No. 352-A, 54 FERC ¶ 61,055 (1991), aff'd sub nom. Town of Norwood, Massachusetts v. FERC, 962 F.2d 20 (D.C. Cir. 1992).

section 211. Similarly, we do not believe that third-party transmission customers should subsidize existing customers. We believe this principle should apply equally to transmission services under both section 211 and sections 205 and 206.

A second implication of the fairness principle is that economic harm that could be created during a period of transition from one pricing approach to another should be mitigated to the extent practicable. Solutions to any transition problems arising from pricing reform should balance fairness considerations associated with any reform against the potential efficiency improvements, and should mitigate the hardships arising from any reform. The major purpose of transmission pricing reform should be to provide more efficient price signals, particularly for new transmission uses, and not simply to reallocate sunk costs.

5. Transmission Pricing Should Be Practical

Transmission pricing should be practical and as easy to administer as appropriate given the other pricing principles. A user should be able to calculate how much it will be charged for transmission service. Some pricing proposals may be so complex that they are difficult to understand and analyze. Such complexity, while not fatal, should be balanced by efficiency gains or other advantages produced by such complexity.

IV. Guidance Regarding Pricing Proposals That Conform to the Traditional Revenue Requirement

In addition to the five general principles above, the Commission provides guidance on specific pricing proposals, including examples of acceptable pricing approaches and clarification of limitations on pricing flexibility.

It is important for those involved in transmission pricing discussions and negotiations to have a common understanding of the attributes of various pricing proposals. For example, various parties advocate the use of "megawatt mile" pricing. Several distinct pricing proposals carry the same "megawatt mile" label. Therefore, those proposing transmission pricing reform must provide a clear explanation of their proposal.

As the industry considers possible pricing reform, the following three attributes of any transmission pricing method should be specified to provide a common framework for analysis:

- the method for measuring cost for purposes of rate design: embedded cost, incremental cost, the Commission's current "or" policy, long-run marginal cost, or short-run marginal cost;
- the method for treating power flows: contract path or flow-based approach; and,
- the method for grouping transmission facilities: corporate postage stamp versus more disaggregated approaches, such as zones, or line-by-line methods. 30/

We anticipate that a wide variety of pricing proposals may be reconciled with the traditional revenue requirement. In theory,

30/ Under a line-by-line pricing method, the costs of each transmission line, or segment, are allocated to individual transmission transactions, based on the usage each transaction makes of each line or segment.

acceptable cost-based pricing that satisfies our principles could be designed for many combinations of these possible attributes. For example, prices could reflect incremental cost (the first attribute), be based on flow (the second attribute), and be allocated on a line-by-line basis (the third attribute). A different approach is taken by changing any one of the attributes, e.g., zones instead of lines. Therefore, many varieties of cost-based pricing are possible.

We fully intend to be flexible and to consider innovative, conforming pricing approaches that accommodate the changing needs of the competitive bulk power market. This applies to pricing for firm as well as non-firm transmission services. The pricing principles set out in the prior section are intended to guide RTGs and individual utilities in their consideration of new approaches. To provide further guidance, we discuss below examples of new cost-based pricing methods that we believe can be made consistent with our principles. These examples are intended to be illustrative. Other approaches also may be consistent with the principles. In all cases, we emphasize that pricing reform must have a purpose consistent with the principles. We want transmission pricing that supports good and consistent decision-making by transmission system users and owners.

A. <u>Examples of Specific Pricing Methods That Conform to the Traditional Revenue Requirement</u>

The following pricing approaches are examples of methods that the Commission would find acceptable, assuming an adequate showing by the utility. In this context, a conforming method is one that clearly meets the first two fundamental requirements and demonstrates that it is is capable of satisfying the other three pricing principles (which ultimately may need to be balanced against one another in the Commission's determination of whether the proposed rates are just and reasonable). Of course, the rates resulting from its use must be shown to be just, reasonable and not unduly discriminatory or preferential.

(1) <u>Examples of Acceptable Transmission Pricing By an Individual Utility</u>

A variety of pricing proposals from an individual utility could be acceptable under the five pricing principles. The range of possible approaches includes various combinations of: (1) a traditional contract path approach or a flow-based approach; (2) costs aggregated at the utility level, at a zonal level, or at the line-by-line level; and (3) various cost concepts for rate design, such as embedded cost, "or" cost, incremental cost, or short-run marginal cost. Not all of these possible combinations, however, would necessarily satisfy our principles.

Examples of pricing reform that the Commission would approve if proposed by an individual utility and if they satisfy our principles include:

- zonal "or" pricing based on power flows from zone to zone within a utility, or within the members of a holding company system. Zonal rates should be supported by showing the use made of separate zones by an individual transaction. Such rates should be supported by an explanation of the data base required and the computer modeling needed to implement it.

- flow-based line-by-line rates, based on embedded costs or "or" pricing. Such rates should be supported by an explanation of the data base required and the computer modeling needed to implement it.
- "or" pricing, at the corporate level using the traditional contract path approach. This is the current Commission standard and remains an acceptable pricing policy that satisfies our pricing principles.

(2) Examples of Acceptable Transmission Pricing By an RTG

The Commission will provide substantial latitude for innovative, conforming pricing proposals by a regional transmission group that meets the requirements of our RTG Policy Statement. 31/ We will give more latitude to RTGs than to individual utilities. This is for two reasons. First, an RTG represents the combined interests of both transmission owners and transmission users, as well as the appropriate participation of state authorities, so pricing proposals are likely to represent an appropriate balancing of those interests. Second, the more attractive proposals for treating regional loop flow problems work better if all the utilities in the region use the same method..

31/ Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (Aug. 5, 1993), III FERC Stats. & Regs. ¶ 30,976 (July 30, 1993); See also PacifiCorp, et al. (on behalf of Western Regional Transmission Association), 69 FERC at ______; Southwest Regional Transmission Association, 69 FERC at ______.

An RTG could propose any pricing reform that is open to an individual utility and also other reforms that address the loop flow issue. Many approaches to reforming transmission pricing tha were suggested in the record of the Pricing Inquiry address the loop flow issue and appear to require a regional approach. From the comments, the Commission discerns two major alternatives to traditional contract path pricing that RTGs could choose for dealing with loop flow:

- "enhanced" contract path pricing, which improves the contractual institutions underlying traditional contract path trading; 32/ and
- flow-based pricing, which refers to pricing designed to reflect the actual or projected power flows associated with a transaction.

Cost-based pricing could be designed to accommodate either of these alternatives. Examples of pricing reform based on a flow-based approach that the Commission would look approvingly on if proposed by an RTG and if consistent with our principles include:

- a MW-mile method, which could be implemented in one of several ways. For example, it could be based on "or" pricing and line-by-line power flows. Alternatively, a MW-mile approach could be based on embedded cost for the whole

32/ "Enhanced contract path" refers to any approach intended to reconcile capacity rights between points of receipt and delivery and actual power flows on a network of lines.

company, allocated as the ratio of transaction-specific megawatt-miles to total megawatt-miles.

- postage-stamp "or" ratemaking at the utility level that is combined with power flow analysis to determine the compensation due to all transmission owners on the parallel paths. This would be a departure from the current contract path approach.
- zonal "or" pricing based on power flow analysis to determine the use a transaction makes of the facilities in each zone.
- short-run marginal cost pricing with transmission prices based on line-by-line losses and opportunity costs caused by power flow constraints.

RTGs may be able to design a pricing approach that combines elements of flow-based pricing with elements of contract path pricing. An example might be contract-path pricing for capacity rights to engage in long-term firm transactions combined with flow-based pricing for short-term, nonfirm transactions that are not covered by such rights. As can be seen from these examples, the Commission will provide RTGs substantial flexibility in choosing among a wide range of pricing approaches.

(3) Examples of Unacceptable Transmission Pricing

As discussed above, any pricing proposal, even a proposal that does not conform to the traditional revenue requirement, must meet the just and reasonable standard of the FPA. Below we list two types of pricing proposals which we find unacceptable.

- **Postage-Stamp "And" Pricing:** Some utilities have proposed so-called "and" pricing, which would add an embedded cost rate to an incremental cost rate for the same service over the same facilities. The proposals have been based on traditional postage stamp ratemaking for which costs are aggregated at the utility level. This type of pricing has been found by the Commission to be unjust and unreasonable. 33/ We cannot see how such an approach is consistent with either our fairness principle or our efficiency principle. 34/
- **Pricing by Individual Utilities to Account for Loop Flow:** While individual utilities may propose new and innovative pricing methods that seek to apportion transmission costs on the basis of

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33/ See Penelec, supra n.5.

34/ The flexibility that we endorse in this Policy Statement regarding cost disaggregation, among other things, addresses the industry's underlying concerns regarding "or" pricing. That is, while we cannot justify pricing that purports to recover two measures of a single cost, allowing the entity to account for costs on a disaggregated basis would permit separate pricing for separate facilities or small groupings of facilities. Hence, we would entertain proposals for flow-based line-by-line "or" pricing. This would permit the use of embedded costs for some lines when this is the higher of embedded or incremental costs, and the use of incremental cost for other lines when this is the higher of embedded or incremental costs.

scheduled flows (e.g., zonal or line-by-line methods), we also believe that it would be inappropriate for individual utilities to reform their own approach to transmission pricing in a way that is inconsistent with regional practices regarding unscheduled or inadvertent flows (loop flow). 35/ We are concerned that individual public utilities may propose approaches to loop flow pricing that lead to a patchwork of mutually inconsistent loop flow pricing methods within a region. Accordingly, a utility's proposal to use flow-based pricing generically to recover the costs of unscheduled inter-utility power flows will be treated as a non-conforming proposal if it is inconsistent with regional loop flow practices, such as use of a contract path convention. 36/

35/ Of course, such individual utility pricing may be appropriate if there are no objections to the loop flow solution from any affected neighboring utilities or transmission customers.

36/ However, a public utility may seek on a case-by-case basis relief from the Commission, including appropriate compensation, in situations in which it is experiencing severe unscheduled loop flows on its system because of specific power transactions by other neighboring utilities and it has been unable to resolve the problem through existing industry mechanisms. See American Electric Power Service Corp., et al., 49 FERC ¶ 61,377 at 62,381 (1989).

V. Pricing Proposals That do not Conform to the Traditional Revenue Requirement

The Commission clearly prefers pricing proposals that are designed not to exceed the traditional revenue requirement. As noted, we believe that given the current industry structure it will be difficult to justify non-conforming proposals. In addition, we believe that the flexibility permitted under this revised transmission pricing policy should be adequate to satisfy the needs of today's electric utility industry, particularly given the current structure of the industry. Nevertheless, the electric utility industry is continuing to evolve 37/ and we must ensure that our policies do not impede the continued development of competitive bulk power markets, or the development of new market structures and transmission arrangements. The Commission will consider pricing proposals necessary to accommodate such developments. Some of the proposals discussed in this proceeding may exceed the traditional embedded cost revenue requirement. Such proposals will be considered provided they meet certain filing procedures and evaluative criteria. We will provide two procedural avenues for considering non-conforming proposals. We will also provide guidance on the type of evidentiary showing necessary to support such proposals.

37/ In recent months, the pace of change in the electric industry has increased dramatically. Certain state proceedings on industry restructuring, as well as proceedings before this Commission, have contributed to the development of innovative proposals by both industry participants and academicians. These evolutionary changes support the need for flexibility and the need to permit non-conforming pricing proposals.

A. Procedures for Proposals That do not Conform to the Traditional Revenue Requirement

Any public utility that seeks non-conforming pricing must hav on file with the Commission an open access transmission tariff offering comparable services. Such comparability tariff must have been accepted for filing by the Commission before a non-conforming pricing proposal will be considered. Moreover, utilities proposing non-conforming transmission pricing must submit such pricing proposals either: (a) in conjunction with a section 205 conforming transmission pricing proposal (the non-conforming proposal would be reflected as alternative "pro forma" rate sheets to the conforming proposal); or (b) in a petition for declaratory order.

(1) Alternative "Pro Forma" Rate Sheets

Under this procedure, the Commission and interested parties would review the non-conforming proposal in conjunction with review of a companion conforming pricing proposal. 38/ The conforming proposal would be subject to the notice and suspension procedures of section 205. The non-conforming proposal would not. The non-conforming proposal would be litigated at the same time as the conforming proposal, but could not take effect, if at all, until the end of the proceeding. If, at the end of the proceeding, the Commission determines that the alternative, non-conforming rate proposal is acceptable under the FPA, the Commission will allow the utility to make a compliance rate filing, and the rates will be put into effect prospectively.

38/ See Pacific Gas Transmission, 66 FERC ¶ 61,384, reh'g denied, 67 FERC ¶ 61,247 (1994), reh'g pending.

This procedure will permit the Commission to determine the extent to which the proposal deviates from the traditional revenue requirement, which may be necessary in determining whether the other features of the proposal are sufficient to offset this. It will also permit an examination of how risk, and hence cost of capital, will vary under the conforming and non-conforming proposals. Another benefit of the alternative "pro forma" rate sheets procedure is that the utility would be able to implement the non-conforming pricing, assuming it was just and reasonable, immediately following the Commission's final order.

(2) Declaratory Order Petition

A utility that wishes to have the Commission consider a non-conforming pricing proposal separate from a rate proceeding may bring the matter to the Commission via a petition for declaratory order. Of course, if the Commission found that the utility's proposal met the statutory criteria, the utility would still need to file a rate reflecting the proposal pursuant to FPA section 205. Presumably the section 205 proceeding would be straightforward (i.e. akin to a compliance filing), however, since the Commission would have already addressed the merits of the proposal in the declaratory order.

B. Criteria for Evaluating Proposals That do not Conform to the Traditional Revenue Requirement

Utilities proposing non-conforming transmission pricing must fully support such proposals. The utility must supply a complete discussion of how the proposal is intended to take account of the pricing principles. The Commission will consider the relative weight of each pricing principle as applied to the facts of each case. We will hold the comparability principle inviolate, however. Absent such support, the Commission will summarily reject the non-conforming proposal even if the utility has agreed to the procedural requirements set forth above.

We will also summarily reject non-conforming proposals that do not submit information showing that the proposal can be expected to:

(a) produce greater overall consumer benefits than a conforming proposal; and

(b) promote competitive bulk power markets. 39/

At a minimum, utilities proposing non-conforming transmission pricing must make a showing of benefits to a broad cross-section of consumers which achieve the following:

(i) greater access and customer choice;

(ii) projected price decreases to customers of delivered power; and

(iii) service flexibility and available products to meet customer needs.

As noted, utilities should also explain how the non-conforming proposal promotes competitive bulk power markets.

39/ The reason we are providing flexibility to consider non-conforming transmission pricing proposals is because we do not want to reject out of hand innovative proposals that could benefit ratepayers. However, we do not intend to waste resources considering proposals whose sole purpose is to provide more revenue to the transmitting utilities. We will summarily reject such proposals.

C. Guidance Regarding Proposals That do not Conform to the Traditional Revenue Requirement

We believe that a non-conforming proposal that results from a diverse group such as an RTG, with fair and nondiscriminatory governance and decisionmaking procedures, would more easily be found just and reasonable than a non-conforming proposal from an individual utility, for the same reason we would afford more deference to a conforming RTG transmission pricing proposal than an individual utility conforming proposal.

Although the Commission has been willing, under appropriate circumstances, to permit market-based pricing for sales of generation, the Commission intends to treat market-based transmission rate proposals as non-conforming. Such rates obviously are not cost-based and the Commission does not believe market-based transmission pricing is appropriate at this time. Although the transmission system has multiple owners, the basic provision of firm transmission service is not competitive in most, if not all, circumstances. Rather, each owner can exert considerable market power by controlling the access, pricing and expansion of its portion of the grid. In addition, regulatory approval for new transmission lines is increasingly difficult to obtain and franchised owners are typically the only entities that possess rights of eminent domain. In these circumstances, unlike for sales of generation, the Commission cannot rely on competitive market forces to discipline prices for firm transmission service. Accordingly, any transmission owner advocating a market-based transmission pricing method must demonstrate how it has alleviated these serious concerns.

Some cost-based pricing approaches adhere to a traditional embedded (depreciated original) cost revenue requirement more closely than others. Replacement cost methods and long-run marginal cost methods of pricing, for example, may result in revenue levels that would exceed the traditional revenue requirement. Pricing methods designed to allow a transmission owner to recover more than its traditional revenue requirement (depreciated original cost) are non-conforming and would need to satisfy the procedures and criteria for non-conforming proposals.

VI. Alternative Institutions and Associated Pricing

The Commission is aware that industry participants have begun to discuss alternative institutional arrangements, such as "pool companies" and "transmission companies." Some of these institutions apparently are intended to facilitate efficient wholesale power trading, and may require alternative approaches for the pricing of transmission services. We believe that these alternative institutions hold great potential. They may assist in the resolution of some difficult federal-state jurisdictional issues and in developing mechanisms for resolving or minimizing stranded cost issues. While we are encouraged that such ideas are under discussion, and are open to considering the particular pricing needs of alternative institutions, these concepts are currently in an early, formative stage. The concepts associated with these ideas have not been adequately explored in this pricing docket or in any other Commission forum. Therefore, concurrent with issuing this Policy Statement, we are opening a separate docket to initiate an inquiry regarding alternative power pooling institutions and their particular pricing needs. 40/

VII. Conclusion

The transition to a competitive wholesale bulk power market depends on the availability of comparable transmission services. Comparable transmission service, in turn, must have appropriate prices, terms and conditions. To that end, the Pricing Inquiry has provided the basis for a productive dialogue among the various entities affected by and participating in the transition to a post-EPAct competitive bulk power market, including transmission owners, transmission users, and Federal and state regulators.

It is critical that transmission services be priced in a manner that appropriately compensates transmission owners and creates adequate incentives for system expansion when such expansion is efficient. Of course, any transmission pricing proposal will have to be evaluated under the standards of the FPA. The Commission must ensure that any such proposal is just, reasonable, and not unduly discriminatory or preferential. A great many of the approaches discussed in this proceeding have the potential to provide better (i.e., more efficient) price signals. But they also have the potential to complicate and prolong the process of determining appropriate rates for transmission services.

This Policy Statement provides a framework for understanding

40/ See Alternative Power Pooling Institutions under the Federal Power Act, Notice of Inquiry, FERC Stats. and Regs. ¶ _____ (1994).

these competing interests, as well as a basis for continuing the transmission pricing dialogue. The Commission has consciously avoided endorsing any particular commenter's specific pricing methodology. Instead, the Policy Statement attempts to provide guidance while still encouraging industry efforts at innovation. Indeed, a great many of the proposals that were submitted during the Pricing Inquiry are highly theoretical and would need to be tested and evaluated in the context of individual cases.

The commenters in the Pricing Inquiry almost unanimously requested that the Commission allow flexibility. To that end, the Commission has attempted to provide pricing principles and general guidance that allow broad experimentation consistent with federal law and the physics of transmission. Certain experiments, particularly pricing methods that attempt to recognize loop flow, clearly require regional involvement and cooperation if they are to be effective. RTGs are encouraged to address such issues as pricing reform and loop flow.

The Commission encourages filing utilities and new groups that may form, such as RTGs and pool companies, to work closely with state regulatory authorities in developing transmission pricing policy. The Commission is committed to cooperating with all affected parties, especially state regulatory authorities, to ensure that any such pricing reform is implemented in an equitable manner and facilitates an orderly transition to a fully competitive bulk power market. Our pricing principles are expected to provide the foundation for the industry to continue its exploration of -

transmission pricing reform.

Finally, the Commission in this Policy Statement has proposed procedures under which non-conforming pricing proposals will be considered. We believe these procedures are flexible enough to permit utilities to propose non-conforming pricing innovations which they believe will benefit ratepayers and promote the development of a competitive bulk power market.

The Commission is making this Policy Statement effective immediately. It is based on the voluminous record developed to date in the Pricing Inquiry. We will accept motions for reconsideration submitted within 30 days in order to help us refine the principles established herein and to provide an opportunity to respond to any questions or clarify any ambiguity. We will apply the Policy Statement to transmission pricing proposals submitted in individual cases filed after the date of this Policy Statement.

List of subjects in 18 CFR Part 2

Administrative practice and procedure, electric power, natural gas, pipelines, reporting and recordkeeping requirements.

By the Commission.

(S E A L)

Lois D Cashell

Lois D. Cashell,
Secretary.

In consideration of the foregoing, the Commission amends Part 2, Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

Part 2 - General Policy and Interpretations

1. The authority citation for Part 2 continues to read as follows:

Authority: 15 U.S.C. 717-717w, 3301-3432; 16 U.S.C. 792-825y, 2601-2645; 42 U.S.C. 4321-4361, 7101-7352.

2. Part 2 is amended by adding § 2.22, to read as follows:

§ 2.22 Pricing Policy for Transmission Services Provided Under the Federal Power Act.

(a) The Commission has adopted a Policy Statement on its pricing policy for transmission services provided under the Federal Power Act. That Policy Statement can be found at 69 FERC 61,086, 59 FR ______ (November ____, 1994). The Policy Statement constitutes a complete description of the Commission's guidelines for assessing the pricing proposals. Paragraph (b) of this section is only a brief summary of the Policy Statement.

(b) The Commission endorses transmission pricing flexibility, consistent with the principles and procedures set forth in the Policy Statement. It will entertain transmission pricing proposals that do not conform to the traditional revenue requirement as well as proposals that conform to the traditional revenue requirement. The Commission will evaluate "conforming" transmission pricing proposals using the following five principles, described more fully in the Policy Statement.

(1) Transmission pricing must meet the traditional revenue requirement.

(2) Transmission pricing must reflect comparability.

(3) Transmission pricing should promote economic efficiency.

(4) Transmission pricing should promote fairness.

(5) Transmission pricing should be practical.

Under these principles, the Commission will also evaluate "non-conforming" proposals which do not meet the traditional revenue requirement, and will require such proposals to conform to the comparability principle. Non-conforming proposals must include an open access comparability tariff and will not be allowed to go into effect prior to review and approval by the Commission under procedures described in the Policy Statement.

NOTE: This Appendix will not appear in the Code of Federal Regulations

APPENDIX A

SUMMARY OF COMMENTS ON THE INQUIRY CONCERNING THE COMMISSION'S PRICING POLICY FOR TRANSMISSION SERVICES IN DOCKET NO. RM93-19-000

The request for comments for the inquiry concerning the Commission's pricing policy for transmission services in Docket No. RM93-19-000 was issued on June 30, 1993. The date for filing responses was extended to November 8, 1993 and reply comments to January 24, 1994. Technical conferences were held on April 8 and 15, 1994. The first day of the conference covered current policy issues. The second day was devoted to advanced pricing concepts and implementation issues.

Comments were received from 165 individual commenters. Five categories of commenters are investor-owned utilities (IOUs, 67 commenters), municipal and cooperative utilities (Muni/Coop, 39 commenters), non-utility generators and independent power producers (NUGs/IPPs, 15 commenters), Regulatory/Government entities (25 commenters), and Others (19 commenters). A list of the commenters is at the end of this appendix; it shows the categories under which their comments are summarized and the acronyms used in this appendix.

A summary of the comments is provided here. The summary is organized in the same manner as the two-day conference (current policy and advanced pricing concepts). The current policy issues are subdivided into eight comment areas and advanced pricing into four comment areas as follows:

Current Policy Issues

1) General Criteria for Transmission Service Pricing
2) "And" Versus "Or" Pricing and Related Incentives
3) Incremental Pricing
4) Network Service
5) Ancillary Services
6) Direction Aspects of Power Flows
7) Non-Firm Transmission Pricing
8) Regional Transmission Groups

Advanced Pricing Concepts/Implementation Issues

1) Alternative Pricing Concepts
2) Distance/Flow-Based Rates
3) Contract Path versus Measured Power Flows
4) Spot Market Pricing

The Commission also received comments on stranded costs in the course of this Inquiry, but these are not addressed in this

Pricing Policy Statement because stranded cost is the subject of a proposed rule. 41/

CURRENT POLICY ISSUES

1. General Criteria for Transmission Service Pricing

The first comment area deals with the proposed criteria for assessing transmission pricing reform. Commenters generally find the criteria proposed in Staff's Discussion Paper 42/ acceptable. However, certain criteria are more readily agreed upon than others. Most commenters uniformly agree that the proposed criteria should: (1) be simple to carry out and to administer; (2) promote efficient use of and investment in the transmission grid; (3) provide appropriate price signals to transmission customers; and (4) ensure equity and fairness during and beyond the transition period.

Other proposed criteria by commenters include that transmission pricing policy should:

- Ensure system reliability;
- Be flexible (*i.e.*, no "one size fits all" pricing methodology) and specifically recognize regional differences;
- Encourage the formation of Regional Transmission Groups (RTGs) and give substantial deference to pricing methodologies developed by RTGs;
- Provide for coordination between state and Federal pricing policies and encourage collaborative policy development;
- Provide for grandfathering of existing contracts and arrangements when implementing any new policies;
- Promote competition in generation;
- Unbundle rates for transmission services;
- Ensure nondiscriminatory rates, terms, and conditions;
- Not allow native load customers to subsidize firm wheeling;

41/ Docket No. RM94-7-000, Notice of Proposed Rulemaking, June 29, 1994

42/ Staff appendix to Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, FERC States. & Regs. ¶ 35,024 (1993).

- Give deference to negotiated agreements (with some commenters adding, where equal bargaining power is involved);

- Ensure rate predictability and transparency of rate derivation; and,

- Allow customers an option to have stable prices over time (although this would not limit parties to fixed rate contracts).

One criterion emphasized by most commenters is that the Commission should exercise maximum flexibility in pricing transmission service. Specifically, many commenters stress that the Commission should not attempt to rigidly apply a single transmission pricing methodology in all cases, to all entities, or to all regions. A general concern raised is that the Commission must recognize the substantial differences present between customer groups, utilities, state and local regulatory bodies, and regional differences. Accordingly, the Commission must resist the temptation to apply one pricing methodology in all cases.

One common view expressed by many Muni/Coops commenters is that the industry must move from a structure where multiple transmission system pricing occurs to a structure where transmission is viewed on a regional basis in conjunction with the development of large, regional power markets. Many commenters advocate the regional transmission grid approach but differ in how the industry and the Commission should advance toward this goal. Some appear to take a more cautious approach. For example, some commenters note that the Commission can only obtain meaningful answers to the questions posed in its transmission pricing inquiry if it first determines the shape of the industry it envisions (such as the regional transmission grid approach or the traditional model based on individually owned and operated transmission systems). **APPA** 43/ contends that before considering changes in traditional transmission pricing, the Commission should develop and articulate a clear statement of its "vision" for the electric industry and specify "where the industry is going, how it will get there, likely impediments, and what steps are necessary for that vision to be fulfilled." Many Muni/Coops commenters also argue that the Commission must first determine if the benefits of transmission pricing reform will outweigh the costs of such reform.

Several Regulatory/Government entities commenters recommend that the following general principles be included in addition to the Commission's proposed criteria:

The Commission's pricing policies should reflect differences

43/ Commenters are referred to by acronym here; acronyms are defined in a list at the end of this appendix.

between the rights and responsibilities of native load customers (including retail and wholesale requirements customers) and other users of the transmission system; any transmission pricing policy must ensure that native load customers will be held harmless; and,

The Commission should seek to promote voluntary resolution of case-specific pricing issues by giving appropriate deference to consensual agreements produced through arms-length negotiations involving all affected parties.

NARUC proposes a consultative process to develop complimentary policies that truly coordinate and render coherent regulation of transmission service. The general goals include coherence of public policy, economic efficiency and reliability in electricity markets, efficiency of processes and decision-making, dialogue between federal and state decision-makers and appropriate input from constituent groups and affected parties as necessary. The **Pennsylvania Commission** concludes that without careful consideration of the role of state agencies and their interest in economic and environmental impacts, bulk power wheeling as envisioned by the Commission is, and will remain, a theoretical, economic model.

2. "And" versus "Or" Pricing and Related Incentives

The "and" versus "or" issue dominated the pricing comments. While arguments on all sides of the issue were expressed, the commenters generally opposed the Commission's current corporate "or" policy and alternatively advocated either some form of the "and" pricing method or corporate-average embedded cost-based rates. The positions of the commenters are described below:

The "And" Method: Most IOUs, most Regulatory/Government entities and some Other entities support the "and" methodology. These commenters state that the Commission's "or" pricing policy does not hold the native load customers harmless and violates FPA section 212(a) (because native load customers and shareholders subsidize third party wheeling customers). When additional facilities are needed to serve third party wheeling load, and incremental (or opportunity) costs are greater than average embedded cost, native load customers subsidize that service (because no cost recognition is given to the third party's use of the existing transmission system, without which the transmission service could not be provided). Additionally, if incremental expansion cost related to third party transmission requests are not allowed by state regulators in retail rates, the transmitting utility will not be made whole. Finally, the Commission's policy on opportunity cost which applies the "higher of" test over the entire transaction period instead of an hourly basis precludes opportunity cost recovery in most cases, sends the wrong hourly price signals to transmission customers, and is overly burdensome administratively.

The "Or" Method: Most NUGs/IPPs commenters agree that the Commission's current corporate "or" policy sends the correct price signal for third-party transmission (as long as opportunity costs are "legitimate and verifiable" and continue to be capped at incremental expansion costs). However several commenters oppose pricing based on opportunity costs (as monopoly rents for a constrained system).

The Average Embedded Cost Method: Most of the Muni/Coops, some NUGs/IPPs, and some Other entities generally support the return to traditional corporate-average embedded cost-based rates. The majority of the Muni/Coops commenters and some of the Other commenters oppose both the "or" and the "and" transmission pricing methods (as yielding excessive rates and impeding the competitive generation market that EPAct permits). Such commenters recommend the traditional policy of charging average embedded cost-based transmission rates. Many of these commenters argue that a transmission-dependent utility (TDU) cannot be considered a "marginal" customer, subject to incremental and opportunity cost pricing, because the transmission system was designed to accommodate the TDU's use and has been paid for proportionally by the TDU. Furthermore, these commenters argue that applying incremental pricing to TDUs is anticompetitive and inconsistent with the EPAct because (1) it forces TDUs to favor power purchases from the host utility over those from a competing power supplier, and (2) TDUs compete with the host utility for requirements customers (who are charged an average embedded cost rate by the host utility).

Commenters views regarding the incentives and disincentives inherent in corporate "or" pricing primarily fall into three basic positions:

1) Although groups disagreed among themselves on how to calculate various cost-based transmission rates, most Muni/Coops, most Regulatory/Government entities, most NUGs/IPPs, and some Others do not believe in allowing any incentives, or premiums above cost-based rates, properly calculated. Most of these commenters agreed that, when a monopoly resource is involved, such incentives amount to allowing "monopoly rents." Transmission is and will remain a natural monopoly, therefore, no incentive is needed beyond recovery of the transmitting utility's prudently-incurred costs and a fair return on its invested capital. Premiums allow the transmission monopolist a competitive advantage in the generation market. Furthermore, there is no need for incentives with the passage of the transmission provisions of the Energy Policy Act; the legal requirement to provide transmission service is sufficient incentive.

2) Most NUGs/IPPs believe the current incentives provided by the

incremental pricing part of the "or" policy are appropriate. However, many of these commenters oppose pricing based on opportunity costs (as monopoly rents for a constrained system).

3) Those advocating "and" pricing, such as most IOUs and some Others, believe that further incentives are needed. The current "or" policy does not sufficiently compensate utilities for all costs of providing service, thus effectively requiring native load customers to subsidize transmission customers. If utilities are forced to absorb potential cost underrecovery and the risk associated with the "or" pricing methodology, then the rate of return should be adjusted to reflect greater risks assumed by engaging in third party wheeling transactions.

3. Incremental Cost Pricing

Under the Commission's current corporate "or" policy, third-party transmission users may be required to pay the incremental cost of a grid expansion if the incremental cost of the expansion is greater than corporate-average embedded cost. Such incremental pricing can be structured in one of two ways — a *contract* approach in which each user pays the incremental cost of the upgrade it occasions, and an *average* incremental price based on the average cost of all upgrades to the transmission system for a group of users.

Most, though not all, commenters believe that contract pricing is the preferred pricing model. IOUs in particular favor contract pricing because it provides more certainty that a utility's revenue requirements are fully recovered. If incremental pricing increases the risk of less than full revenue recovery, either shareholders or residual customers will bear the extra risks. Most wholesale customers also appear to favor contract pricing, though some have concerns that contract pricing, with different prices for each user, may result in price discrimination. These commenters suggest that similarly situated customers should have the same price, but have different notions of what this would mean.

For many of the difficult practical issues associated with incremental pricing, there is no consistent position taken by all or even most members of any interest group that supports incremental cost pricing. For example, many commenters believe that average incremental cost pricing gives the wrong price signal to both the transmission owner and user. These commenters are concerned that the average incremental cost price does not signal the true cost of the transmission service. A few commenters argue that this will result in underbuilding of the transmission system. Others suggest that this may result in overbuilding, although IOUs in particular doubt this result, given the difficulties inherent in siting, certification and construction of new transmission facilities.

Additionally, commenters are split on the issue of administrative costs and other implementation problems that may result under each pricing model. Some commenters argue that contract pricing entails maintaining separate contracting provisions for each user, with attendant high costs. Other commenters suggest that average incremental cost pricing is more difficult, given the need to estimate incremental costs, and the problems associated with changing average incremental rates as a result of incremental cost changes. One commenter suggests that it is simply not possible to reconcile average incremental pricing with an embedded cost transmission revenue requirement.

Several commenters suggested that it would be appropriate to allow utilities some flexibility to adopt either incremental cost pricing approach. The challenge for the Commission would be to determine under what conditions such flexibility would be warranted, in order to protect both the third-party transmission users and the remaining wholesale and retail customers from being charged for inappropriate costs. Other commenters suggest that some experimentation may be in order. If the Commission chooses to allow such experimentation, it may learn a great deal about the magnitude of the practical problems, as well as potential solutions for those problems.

4. Network Service

The Staff Discussion Paper defined network service as allowing the user to vary its schedule and points of delivery and receipt without paying additional charges for each change. Commenters were asked to discuss the reasonableness of this definition and to provide recommendations on pricing network service. Most IOUs assert that utilities cannot provide third party transmission users with unlimited flexibility in choosing and switching points of receipt and delivery. Unless the transmission customer specifies the points of receipt and delivery, the nature of the generation, and the loads to be served, the transmitting utility will have no way to determine the impact of the proposed network arrangement on its system in terms of either reliability or cost. Unlimited flexibility could require transmission upgrades and make long term planning more difficult (with the potential for overbuilding). If network service is to include unlimited scheduling flexibility, it should be considered a premium service (priced higher than point-to-point service) since it requires higher transmission capacity margins to ensure reliability.

Most Muni/Coops, Regulatory/Government entities, NUGs/IPPs and some Other commenters agree with the Commission's definition of network service. Most Muni/Coops, NUGs/IPPs and some Other commenters insist that network service should be priced on an average embedded cost basis (with no non-cost-based network rate premiums or percentage adders). These commenters argue that such premiums would place network customers at a permanent competitive disadvantage in obtaining economical generation sources and in generation sales, compared to the transmitting utility. Many commenters agree that network access should not be totally flexible, nor be unduly rigid with reservation requirements and excessively advanced scheduling requirements; rather, they believe it should be subject to the same conditions faced by the transmitting utility, and provide access to transmission on an "as if owned" basis.

APPA asserts that it is not aware of any party that is seeking network access without regard to the control area utility's own transmission needs, or that is requesting network service with total flexibility, i.e., no scheduling or backup requirements. **APPA** adds that it agrees with **EEI** on two points concerning utilities receiving network service: "they should state in planning models the sources of power that most probably will be used to serve loads, and they should schedule generation to serve load with the transmitting utility."

Regulatory/Government entities generally agree that accurate pricing of network service will depend on the nature of the network and any revenue pooling between transmission providers. Therefore, Regulatory/Government entities urge the Commission to be flexible and not mandate any particular method for pricing network service.

5. Ancillary Services

The Staff Discussion Paper gave examples of ancillary services and requested comments on other examples (including how such services should be priced). Most IOUs recommend that unless third party customers obtain ancillary services elsewhere, they should compensate the wheeling utility for the services provided to prevent the native load customers from subsidizing these services. IOUs note that as bulk power markets are becoming more competitive and independent power producers are supplying ever increasing amounts of generation, these support type services that were once provided on a reciprocal basis among utilities are not being provided by many suppliers because they are either unwilling or unable to provide such service.

One of the main concerns of the Muni/Coops commenters is that costs associated with ancillary services should not already be included in the average cost-based transmission rate. Additionally, several commenters insist that transmission customers should be given the option to provide such services themselves, or obtain them from other utilities, and receive full credit. These commenters also express concern regarding discriminatory pricing. Such commenters urge that any charges for ancillary services assessed to a transmission customer should be the same as the costs faced by the transmitting utility for the same service.

NUGs/IPPs. Regulatory/Government entities and Others generally did not address this issue.

Other claimed ancillary services include: Backup and Standby Service; Loss Service; Redispatch Costs; Control Center Service; Emergency Services; fast starts, "BlackStart" capability (starting up a generating station with no external power supply), regulation, and stability.

Graves, et al. proposed that ancillary services could be provided by an independent entity, which they call a "Poolco" (e.g., an existing power pool, an RTG, NERC subregion, or consortium of independent generators). Their version of a Poolco would not participate directly in real power MW brokerage or energy supply; rather, it would own and operate a relatively small collection of generation and flow control assets sufficient to assure the integrity of the system, relying on tieline flows, voltage measurements at a few key load centers, and forecast control-area load changes (over the next few hours).

6. Direction Aspects of Power Flows

The power flows caused by a transmission transaction may be either with, or counter to, the prevailing flows. The incremental effects of transmission transactions may also raise issues with respect to the use of multiple parallel paths and the incremental effects on transmission losses.

A. Directional Flows

Most commenters (most IOUs, some Muni/Coops, and some Regulatory/Government entities) suggest that charges should be applied for all power flows on a system (regardless of direction). Several commenters indicate that reverse flows exist only under some system conditions and that changes in transmission system configuration (due to line outages) and changes in generating unit dispatch, may eliminate any reverse flows. Such commenters also claim that all transmission elements support all power flows. Accordingly, reverse flows should only be credited if they provide a direct economic benefit to the utility.

Other commenters (some Muni/Coops, some Regulatory/Government entities, and most Others) argue that it is important for the Commission to adopt a transmission pricing method which recognizes flow direction and discounts transmission service which "unloads" the system and helps to relieve constrained transmission lines. These commenters suggest that this type of pricing signal encourages the most efficient use of the transmission system.

B. Loop Flows

Few comments on this issue were received from Muni/Coops, NUGs/IPPs, Regulatory/Government entities and Others. There did not appear to be any consensus among the IOUs on the best method to address loop flow problems.

Southern Companies indicates that loop flows were often short-lived and were viewed as part of the normal interconnected operations among utilities. It was once commonly viewed that loop flows on one utility's system would most likely be offset by loop flows on its neighboring systems. In instances where the flows were a problem, negotiated solutions were reached. **LG&E** notes that bulk power transactions were once predominantly multi-directional and covered shorter distances so that transactions evened out over time.

However, in today's marketplace transactions are more numerous, over longer distances, and unidirectional. As a result, loop flows do not even out over time. In the new competitive environment, **Southern Companies**, **AEP** and **Northern States** claim the situation has changed. In the emerging bulk power market, many more long term firm transactions in a single direction are contemplated which will more adversely impact flows over interconnected systems. These commenters state that it also may be more difficult in a competitive environment to negotiate solutions to parallel flow problems. **Consumers** believes that uncertainty about loop-flow compensation may be a significant potential barrier to the more rapid development of competition among new generators.

C. Losses

Many commenters (some IOUs, most Muni/Coops, some Others) argue that losses vary in proportion to the distance over which the energy is moved, and accordingly, contend that incremental losses send a more appropriate price signal to the customer (by more closely linking cost causation and cost recovery). **Tabors** claims that efficiency requires pricing losses at the margin, which can be accomplished using load flow calculations and Optimal Power Flow modeling techniques. On the other hand, many commenters recommend average system line losses. Several of these commenters insist that they should be charged for line losses on the same cost basis that the transmitting owners use for their own dispatch and charge their native load customers.

7. Non-Firm Transmission Pricing

A fundamental issue of non-firm transmission service pricing is whether or not a contribution to capital costs over and above the variable cost of transmission (losses and opportunity costs) should be made for non-firm service. One view is that users of non-firm service should not pay for capacity costs since capacity is not built for them and their service can always be interrupted. On the other end of the spectrum are those that advocate a contribution of up to 100 percent of fixed costs, since firm customers need to be compensated for the use of the transmission system that they support in its entirety.

Most IOUs indicate that non-firm users of the transmission system should contribute to the capital costs of the system. They believe the Commission should rely on its historical precedent, which allows a contribution of up to 100 percent of fixed costs for non-firm service with the revenues being credited to native load customers. Some believe the shareholders should receive some of the revenues from non-firm transactions. Other commenters suggest minimal regulation of non-firm transactions as long as the price does not exceed a cap equal to its fully allocated transmission costs.

Many of the Muni/Coops commenters state that there are no fixed costs associated with providing non-firm transmission services and note that groups in different parts of the country (e.g., PJM, NEPOOL, MAPP and ERCOT) do not include contributions to fixed costs in non-firm transmission pricing. Many commenters believe that no demand charges for non-firm transmission are necessary and argue that such demand charges may have a negative impact on the efficiencies of the economy energy market for short term transactions. For example, **Consumer Working Group** recommends:

> Limiting non-firm rates to real costs (i.e. losses) would eliminate the artificial dead zone created by the incentive transmission rates now allowed. By granting all market participants (and not just transmission owners) access at cost to non-firm transactions, all consumers would benefit from increased coordination. Such nondiscriminatory, cost-based pricing of non-firm transmission would serve the EPAct's purpose of stimulating competition in bulk power markets and would promote economically efficient generation of electricity as expressly mandated by Section 212(a). (Consumer Working Group Reply at 21)

8. Regional Transmission Groups

All segments of the industry supported the Commission's encouragement of the development of such groups. Many commenters believe that RTGs represent the best method available to deal with the difficult transmission pricing issues presented in Staff's Discussion Paper. Some commenters cautioned that to be successful, RTGs must be certified by the Commission to ensure proper representation of all groups within the electric utility industry. Many commenters anticipate RTGs will facilitate coordinated regional planning, regional measurement of power flows and regional methodologies to determine the price of any firm wheeling transaction within the region. The information available on a regional basis will allow planning to alleviate current and future transmission constraints within the region as well as send a clear price signal to third party customers requesting service. RTG's will also provide information as to what transmission capacity is available and the need for any transmission enhancements within the region to accommodate the requested transaction.

ADVANCED PRICING CONCEPTS/IMPLEMENTATION ISSUES

1. Alternative Pricing Concepts

Numerous commenters proposed alternative pricing methods, other than those pricing methods normally permitted by this Commission. The methodologies advanced by these commenters varied from conceptual ideas to detailed formulas. Certain concepts and methods were advocated by more than one and in some cases several commenters, including:

- Combinations of, or hybrids between, the "or" and the "and" policies, many of which advocated recovery of all incremental costs and some contribution (but not necessarily 100%) to average embedded system costs.

- Variations of recovering strictly incremental or marginal cost pricing; i.e., rates based on long-run incremental cost pricing for long-term firm transmission service and short-run marginal costs for other transactions. Another commenter proposed short-run marginal costs for transactions not requiring upgrades.

- Numerous proposals for a single transmission owner and for regional pricing, planning and operating approaches; for example: 1) the forced divestiture of all utilities' transmission assets and formation of a single transmission owning national grid company or "gridco"; 2) joint ownership, operation and pricing of all transmission within an established region with all transmission users obtaining load ratio shares of the regional grid and paying on an average embedded load ratio basis; 3) a proposal simply to price transmission in a region as if there were a single transmission owner; and 4) many suggestions for the Commission to further examine the companies formed in Norway, Sweden, New Zealand, Victoria (Australia), India, Argentina, England and Wales.

- Establishing a secondary market in transmission rights — transmission purchasers having the capacity to contractually broker, resell, trade, partially assign, or assign firm purchase entitlements as they choose. Capacity trading will provide for the repackaging of capacity rights to fit market needs, thereby creating a market mechanism to "price" and "clear" transmission services as a commodity.

Numerous proposals advocating that the Commission require the unbundling of rates for transmission and sales services. Unbundling would require transmission owners to include a separate (transparent) transmission charge in any use of the utility's transmission system for the delivery of power in the wholesale market, including that utility's own wholesale sales. Transmission terms and conditions should be the same for all wholesale transactions, regardless of whether the seller is the owner of the transmission facilities used for the transaction.

2. Distance/Flow-Based Rates

Alternatives to postage stamp rates would make rates sensitive to the transmission distance involved in providing the service. Alternatives suggested include various "MW-mile" approaches and other methods based on load flows (such load flow methods can also treat issues involving multiple parallel paths and transmission losses associated with particular transmission transactions). Commenters' support is split between distance-based pricing and postage stamp rates.

Regulatory/Government commenters express a clear preference for distance-sensitive rates (over postage stamp rates). Most Regulatory/Government entities, some IOUs, some NUGs/IPPs, and some Others argue that distance-based rates would compensate the transmitter for increased transmission costs as more of its system is used. This encourages more efficient use of the transmission system. Where more miles of the transmission system are utilized, distance-sensitive rates reflect the proper cost causation. Several commenters believe that simplified distance-sensitive pricing methods, such as some MW-mile methods, used in conjunction with approaches such as zonal pricing that reflects system constraints, would be appropriate. Numerous commenters advocating distance-based rates recommend zonal pricing as a compromise between the administrative simplicity of postage stamp rates and more appropriate price signals of certain distance-based rate methods.

Most Muni/Coops, some IOUs, and some NUGs/IPPs support postage stamp rates and criticize distance-sensitive pricing due to its dependence upon power flow studies involving a base and a change case. Many commenters note that power flows on a transmission system are in constant change, thereby creating a very large number of possible system parameters that could be included in load flow analyses and therefore requiring many simplifying assumptions. Consequently, any attempt to derive a normal base case power flow on which to model an incremental power flow would be flawed and unreliable, particularly for individual utilities located in heavily interconnected networks. Therefore, these commenters prefer the administrative convenience of postage stamp rates over the complexity and questionable accuracy of distance-sensitive rates based on power flow studies.

3. Contract Path versus Measured Power Flows

The mismatch between the contract path for a transaction and the actual flows creates pricing and equity concerns. Utilities are split regionally on whether to adopt loop flow, or parallel path, pricing reform or retain contract path pricing. Most Western utilities favor retaining contract path pricing. Western utilities maintain that the topology of the WSCC makes it well suited to the use of phase shifters to control the loop flow problem. In addition, the development of Flexible AC Transmission technology may provide additional devices to augment existing control strategies.

Many utilities in the Midwest and the East favor adopting loop flow pricing because over time contract path pricing has left many systems uncompensated for parallel flows. These utilities argue that contract path pricing is outmoded because (1) transmission services have become long-term single direction transactions, (2) many new market entities do not own transmission so that reciprocity is not possible, and (3) negotiated solutions are less possible as competition expands.

Many utilities in favor of loop flow pricing are concerned that the associated transition costs are formidable. Parallel flows constantly change with changes in the dispatch of generation. In addition, some utilities urge the development of RTGs first before implementing loop flow pricing. In fact, there is general agreement that RTGs are an appropriate institution for addressing many of the industry's problems including pricing issues and the siting and construction of transmission facilities.

While there is widespread dissatisfaction with contract path pricing outside of the West, there is considerable uncertainty about how to address the parallel flow problem effectively. Many parties believe that contract path pricing and loop flow pricing can be combined to address the problem, while other parties believe that these two methods are incompatible. Still other parties offer an array of variations on the contract path pricing and loop flow pricing methods. For example, **Hogan's** "contract network" approach and **PacifiCorp's** proposal are variations on the contract path pricing method. The GAPP experiment, which the **Interregional Transmission Coordination Forum** stresses as the way to identify the pricing method to compensate for parallel flows, is a preliminary type of loop flow pricing. The Texas Planned Capacity Wheeling Service and **Southern Company's** Transmission Cost Actual Path Pricing are also examples of loop flow pricing. Finally, many parties argue that alternatives to contract path pricing should be pursued on a voluntary basis.

4. Spot Pricing for Non-firm Transmission

Few commenters express outright opposition to spot pricing, but most advocate a cautious approach to implementation. Those in the latter category comprise a diverse group of IOUs (including EEI), coops, state commissions and industrial groups. Many suggest that spot pricing schemes should continue to be studied, but not considered for implementation at this time. Some encourage the Commission to conduct experiments similar to the Southwest Bulk Power Experiment and the WSPP.

Those opposed to spot pricing generally believe that the benefits are not worth the costs. Some argue that the successful implementation of spot pricing for transmission requires a competitive market in generation that does not now exist. However, some commenters that see promise in spot pricing argue that the necessary market institutions and technology exist today. They cite the operation of tight power pools, electronic bulletin boards, and the WSCC experiment as evidence of this fact.

Some commenters argue that the "up to" transmission rates that many utilities now use for non-firm transmission service effectively approximate spot transmission pricing. However, others believe that rate design for spot transmission pricing raises a number of difficult issues, such as the use of one-part versus two-part rates, and the appropriate definition of the cost of transmission service.

Several commenters offer highly developed policy proposals or technical models for use in implementing spot pricing. In particular, **Hogan** and **Putnam** believe that all participants in the power market should have access to economic dispatch with marginal cost pricing. **Hogan** argues that transmission rights cannot be built on the traditional wheeling model that assumes that specific power moves to specific customers. He claims that only by stepping away from such misleading assumptions can the Commission design a set of pricing and access reforms that are consistent with the underlying economics and will support an efficient competitive electricity market.

LIST OF COMMENTERS IN THE TRANSMISSION PRICING POLICY INQUIRY

The following parities filed either initial or reply comments. Acronyms used in this appendix are defined here.

Investor-Owned Electric Utilities and Associations

1. Allegheny Power Service Corporation
2. American Electric Power System Companies (AEP)

3. Arizona Public Service Company
4. Association of Electric Companies of Texas
5. Atlantic City Electric Company
6. Bangor Hydro-Electric Company
7. Carolina Power and Light Company
8. Centerior Energy Corporation
9. Central and South West Services, Inc.
10. Central Illinois Public Service Company
11. Central Louisiana Electric Company
12. Commonwealth Edison Company
13. Consumers Power Company/CMS Energy (Consumers)
14. Dayton Power and Light Company
15. Detroit Edison Company
16. Dominion Resources, Inc.
17. Duke Power Company
18. Duquesne Light Company
19. Edison Electric Institute (EEI)
20. Entergy Services, Inc.
21. Florida Power Corporation
22. Florida Power Corporation, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation
23. Houston Lighting & Power Company
24. Idaho Power Company
25. Indianapolis Power & Light Company
26. Iowa-Illinois Gas and Electric Company
27. LG&E Energy Corp.
28. Long Island Lighting Company
29. Louisville Gas and Electric Company
30. Midwest Power Systems, Inc.
31. Montana Power Company
32. New England Power Service
33. New York State Electric & Gas Corporation
34. Niagara Mohawk Power Corporation (Niagara Mohawk)
35. Northeast Utilities System Companies
36. Northern States Power Company (Northern States)
37. Ohio Edison Company
38. Otter Tail Power Company
39. PacifiCorp
40. Pacific Gas and Electric Company
41. Pennsylvania-New Jersey-Maryland Interconnection
42. Pennsylvania Power & Light Company
43. Philadelphia Electric Company
44. Portland General Electric Company
45. PSI Energy Inc. and Cincinnati Gas & Electric Company
46. Public Service Company of Colorado
47. Public Service Company of New Mexico
48. Public Service Electric and Gas Company
49. Puget Sound Power & Light Company
50. San Diego Gas & Electric Company
51. Sierra Pacific Power Company
52. South Carolina Electric & Gas Company
53. Southern California Edison Company
54. Southern California Gas Company
55. Southern Companies
56. Southwestern Public Service Company
57. Tampa Electric Company

58. Texas Utilities Electric Company
59. Tucson Electric Power Company
60. Union Electric Company
61. United Illuminating Company
62. Unitil Power Corporation
63. Utility Working Group
64. Washington Water Power Company
65. Western Resources, Inc. and Kansas Gas and Electric Company
66. Wisconsin Electric Power Company
67. Wisconsin Public Service Corporation

<u>Municipals, Cooperatives and Government-Owned Electric Utilities and Related Associations</u>

1. Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association
2. Allegheny Electric Cooperative, Inc.
3. American Public Power Association (APPA)
4. Arizona Power Authority
5. Associated Electric Cooperative, Inc.
6. Basin Electric Power Cooperative
7. Bonneville Power Administration
8. California Department of Water Resources
9. City of Anaheim, California
10. City of Vernon, California
11. Colorado Association of Municipal Utilities
12. Colorado Joint Transmission Principles Participants
13. Consumer Working Group
14. East Kentucky Power Cooperative, Inc., Saluda River Electric Cooperative, Inc., and Wolverine Power Supply Cooperative
15. East Texas Cooperatives
16. Florida Municipal Power Agency, Michigan Municipal Cooperative Group and Wolverine Power Supply Cooperative
17. Indiana Municipal Power Agency
18. Irrigation and Electrical Districts Association of Arizona
19. Large Public Power Council
20. Lincoln Electric System
21. Massachusetts Municipal Power Systems
22. Missouri Basin Municipal Power Agency
23. Municipal Electric Authority of Georgia
24. National Rural Electric Cooperative Association
25. Northern California Power Agency
26. Oglethorpe Power Corporation
27. Old Dominion Electric Cooperative, Inc.
28. Public Generating Pool
29. Sacramento Municipal Utility District
30. South Texas Electric Cooperative, Inc. and Medina Electric Cooperative, Inc.
31. Tennessee Valley Authority
32. Transmission Access Policy Study Group
33. Transmission Agency of Northern California
34. Transmission Dependent Systems
35. Turlock Irrigation District
36. Utah Associated Municipal Power Systems
37. Wabash Valley Power Association, Inc.
38. Wisconsin Public Power, Inc. SYSTEM

39. Wisconsin Wholesale Customers

Non-Traditional Utility Generators (NUGs, IPPs, EWGs and QFs), Power Marketers Foreign Entities and Related Associations

1. American Wind Energy Association
2. British Columbia Power Exchange Corporation (POWEREX)
3. California Independent Energy Producers Association
4. Electric Generation Association
5. Enron Power Marketing, Inc.
6. Fuel Managers Association
7. Geothermal Resources Association
8. Hydro-Quebec
9. InterCoast Power Marketing Company
10. Kvaener Energy Development Inc. and Citizens Power & Light Co.
11. LG&E Power, Inc.
12. National Independent Energy Producers
13. National Power Plc
14. Ontario Hydro
15. Torco Energy Marketing, Inc.

State Regulatory Commissions and Other Government Agencies

1. Alabama Public Service Commission
2. California Energy Commission
3. California Public Utilities Commission
4. Florida Public Service Commission
5. Georgia Public Service Commission
6. Idaho Public Utilities Commission
7. Illinois Commerce Commission
8. Indiana Utility Regulatory Commission
9. Kansas Corporation Commission
10. Maine Public Utilities Commission and the Vermont Department of Public Service
11. Massachusetts Department of Public Utilities
12. Michigan Public Service Commission
13. National Association of Regulatory Utility Commissioners (NARUC)
14. Nevada Public Service Commission
15. New York State Department of Public Service
16. Ohio Public Utilities Commission the Ohio Sitting Board
17. Pennsylvania Public Utility Commission
18. Sharp, The Hon. Philip R., Chairman, Subcommittee on Energy and Power
19. Texas Public Utility Commission
20. United States Department of Energy
21. United States Department of Justice
22. Virginia State Corporation Commission
23. Wallop, The Hon. Malcolm, Senate Committee on Energy and Natural Resources
24. Washington State Energy Office
25. Wisconsin Public Service Commission

Others

1. American Forest and Paper Association (American Forest & Paper)
2. Burns, Robert E.
3. Committee on Regional Electric Power Cooperation
4. Direct Electric Inc. (Direct Electric)
5. Drazen-Brubaker & Associates, Inc.
6. Electricity Consumers Resource Council, the American Iron and Steel Institute and the Chemical Manufacturers Association
7. Electric Power Research Institute
8. Ernst & Young Utilities Consulting/Frederick L. McCoy
9. Hogan, William W. (Hogan)
10. Incentives Research, Inc., and Massachusetts Institute of Technology (Graves, et al.)
11. Institute of Electrical and Electronic Engineers
12. Interregional Transmission Coordination Forum
13. Joint Consumer Advocates
14. Lively, Mark B.
15. New York Mercantile Exchange
16. Ohio Office of the Consumers' Counsel
17. Putnam, Hayes & Bartlett, Inc. (Putnam)
18. SASY Inc.
19. Tabors Caramanis & Associates (Tabors)