STATE OF NEW HAMPSHIRE

SUPREME COURT

2009 TERM

No. 2009-0359

Briar Hydro Associates v. Public Service Company of New Hampshire
(New Hampshire Public Utilities Commission)

APPENDIX TO BRIEF OF RESPONDENT

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Gerald M. Eaton, Senior Counsel No.727
Public Service Company of New Hampshire
780 North Commercial Street, P. O. Box 330
Manchester, NH 03105-0330
(603) 634-2961
FAX (603) 634-2438

APPENDIX TO BRIEF OF RESPONDENT

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STATE STATUTES

RSA 21:2 Common Usage.

Words and phrases shall be construed according to the common and approved usage of the language; but technical words and phrases, and such others as may have acquired a peculiar and appropriate meaning in law, shall be construed and understood according to such peculiar and appropriate meaning.

RSA362-A:1-a Definitions.

In this chapter:

III. "Limited producer" or "limited electrical energy producer" means a qualifying small power producer or a qualifying cogenerator, with a total capacity of not more than 5 megawatts.

VI. "Qualifying cogeneration facility" means a cogeneration facility which the commission determines meets such requirements, including requirements respecting minimum size, fuel use and fuel efficiency, as the commission may prescribe and 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.

VII. "Qualifying cogenerator" means the owner or operator of a qualifying cogeneration facility.

VII-a. "Qualifying facility" means either or both of a qualifying small power production facility or qualifying cogeneration facility.

VIII. "Qualifying small power producer" means the owner or operator of a qualifying small power production facility.

IX. "Qualifying small power production facility" means a small power production facility which the commission determines meets such requirements, including requirements respecting fuel use, fuel efficiency and reliability, as the commission may prescribe and which is owned by a person not primarily engaged in the generation or sale

RSA 362-A Limited Electrical Energy Producers Act

RSA 362-A:2,

RSA 362-A:4

RSA 362-A:5

See, 1978 NH Laws 32, PSNH Appendix Pages 3-4, *infra.*

RSA 541:13 Burden of Proof.

Upon the hearing the burden of proof shall be upon the party seeking to set aside any order or decision of the commission to show that the same is clearly unreasonable or unlawful, and all findings of the commission upon all questions of fact properly before it shall be deemed to be prima facie lawful and reasonable; and the order or decision appealed from shall not be set aside or vacated except for errors of law, unless the court is satisfied, by a clear preponderance of the evidence before it, that such order is unjust or unreasonable.

1983 N.H. Laws 395:1 *See,* PSNH Appendix Pages 5-6, *infra.*

not shorten the time period established in subparagraphs (a) and (b) of this paragraph.

III. Where the action is brought to recover indemnity or contribution for damages paid to or claimed by another, the action must be commenced within the same period established in RSA 507-D: 2, I, II, plus 90 days.

IV. The limitation periods established in RSA 507-D: 2, I, II and III do not apply to actions based on the defendant's fraudulent misrepresentation, concealment or nondisclosure, nor to any actions based upon a written contractual obligation which provides for a different period of limitation, nor to actions brought under RSA 382-A: 2-313, 2-314 or 2-315 which do not seek damages for or on account of injury to person or property.

507-D: 3 **Modification or Alteration of Products.** In any product liability action, the defendant may be held liable only for harm that would have occurred if the product had been used in its unaltered and unmodified condition and shall not be held liable for harm arising in any part from alteration or modification of the product by another. For the purpose of this section, alteration or modification includes failure to observe routine care and maintenance, but does not include ordinary wear and tear or alterations or modifications made in accordance with specifications or instructions furnished by the defendant.

507-D: 4 **Discoverability of Risk.** In product liability actions brought by or in consequence of harm to a user, it is an affirmative defense that the risks complained of by the plaintiff were not discoverable using prevailing research and scientific techniques under the state of the art and were not discoverable using procedures required by federal or state regulatory authorities charged with supervision or licensing of the product in question. Discoverability of risks shall be measured as of the time the manufacturer parted with possession and control of, or sold the product in question, whichever occurred last.

507-D: 5 **Applicability.** This chapter applies to all product liability actions accruing after its effective date and, as to such actions, shall supersede any inconsistent provision of law. In addition, this chapter applies to causes of action accruing prior to its effective date upon which no action has been instituted as of its effective date, except that the time for bringing such actions as specified in RSA 507-D: 2 shall be computed from the effective date of this chapter.

31: 2 **Commission to Study Product Injury Reparations.**

I. A commission to study product injury reparations is hereby established, consisting of the following members: The insurance commissioner, the commissioner of resources and economic development and no more than 13 other members to be appointed as follows: 2 who represent manufacturers or sellers of products, to be appointed by the Business and Industry Association of New Hampshire; 2 who are members of the legal profession, to be appointed by the New Hampshire Supreme Court; 2 who represent the insurance industry, to be appointed by the New Hampshire Product Liability Stabilization Committee; 2 senators to be appointed by the president of the senate; 3 members of the house of representatives, to be appointed by the speaker of the house; and 2 representatives of the general public, to be appointed by the governor. The insurance commissioner shall be the chairman of the commission.

II. The commission shall monitor the effectiveness of section 1 of this act in improving the availability and affordability of product liability insurance; shall review other existing laws and practices which bear on the availability and affordability of such insurance; and shall recommend such changes as may be necessary to increase availability and affordability of such insurance, while at the same time allowing just compensation to those suffering injury from products.

III. An interim report shall be prepared and submitted by the commission on April 1, 1979, to the governor, the president of the senate and the speaker of the house, with a final report due on or before January 1, 1980.

31: 3 **Effective Date.** This act shall take effect 60 days after its passage.

[Approved June 23, 1978.]

[Effective date August 22, 1978.]

CHAPTER 32.

AN ACT RELATIVE TO PROVIDING EXEMPTIONS FROM PUBLIC UTILITY STATUS FOR CERTAIN ELECTRICAL ENERGY PRODUCERS AND SETTING RATES FOR SALE OF POWER GENERATED BY THOSE EXEMPTED PRODUCERS.

Be it Enacted by the Senate and House of Representatives in General Court convened:

32: 1 **New Chapter.** Amend RSA by inserting after chapter 362 the following new chapter:

CHAPTER 362-A

LIMITED ELECTRICAL ENERGY PRODUCERS ACT

362-A: 1 **Declaration of Purpose.** It is found to be in the public interest to provide for small scale and diversified sources of supplemental electrical power to lessen the state's dependence upon other sources which may, from time to time, be uncertain.

362-A: 2 **Exemption of Limited Electrical Energy Producers.** Producers of electrical energy, not involving the use of nuclear or fossil fuels, with a developed output capacity of not more than 5 megawatts shall not be considered public utilities and shall be exempt from all rules, regulations and statutes applying to public utilities.

362-A: 3 **Purchase of Output of Limited Electrical Energy Producers By Public Utilities.** The entire output of electric energy of such limited electrical energy producers, if offered for sale, shall be purchased by the electric public utility which serves the franchise area in which the installations of such producers are located.

362-A: 4 **Payment by Public Utilities for Purchase of Output of Limited Electrical Energy Producers.** Public utilities purchasing electrical energy in accordance with the provisions of this chapter shall pay a price per kilowatt hour to be set from time to time by the public utilities commission.

362-A:5 **Settlement of Disputes.** Any dispute arising under the provisions of this chapter may be referred by any party to the public utilities commission for adjudication.

32:2 **Effective Date.** This act shall take effect 60 days after its passage.

[Approved June 23, 1978.]

[Effective date August 22, 1978.]

CHAPTER 33.

AN ACT CONCERNING THE ASSIGNMENT OF TEMPORARY JUSTICES OF THE SUPREME COURT.

Be it Enacted by the Senate and House of Representatives in General Court convened:

33:1 **Justices.** Amend RSA 490:1 by striking out said section and inserting in place thereof the following:

490:1 **Justices.** The supreme court shall consist of a chief justice and 4 associate justices, appointed and commissioned as prescribed by the constitution.

33:2 **Temporary Justices.** Amend RSA 490:3 by striking out said section and inserting in place thereof the following:

490:3 **—Disqualification; Temporary Justices.**

I. The provisions as to the disqualification of justices of the superior court apply to justices of the supreme court. Whenever a justice of the supreme court shall be disqualified or otherwise unable to sit in any cause or matter pending before such court, the chief or senior associate justice of the supreme court may assign another justice to sit according to the provisions of paragraph II of this section.

II. Upon the retirement, disqualification, or inability to sit of any justice of the supreme court, the chief justice or senior associate justice of the supreme court may assign a justice of the supreme court who has retired from regular active service to sit during supreme court sessions while the vacancy continues, or he may notify the chief justice or senior associate justice of the superior court of such vacancy. Upon such notification, the chief justice or senior associate justice of the superior court shall provide the supreme court for each day of sitting during a session while the vacancy shall continue with the names of 2 or more superior court justices in regular active service or who are retired and are not otherwise disqualified. The chief justice or senior associate justice of the supreme court may then assign a justice to sit temporarily on the court from among those superior court justices whose names have been provided.

III. A justice assigned to sit temporarily on the supreme court pursuant to paragraph II of this section shall have all the authority of a supreme court justice to hear arguments, render decisions, and file opinions. No justice shall be assigned to sit on the supreme court in the determination of any cause or matter upon which he has previously sat or for which he is otherwise disqualified nor without his consent.

33:3 **Quorum.** Amend RSA 490:7 by striking out said section and inserting in place thereof the following:

490:7 **Quorum.** Such sessions may be held by 3 justices. A lesser number, or the clerk, if no justice attends, may adjourn the sessions from day to day until 3 justices attend. If one or more of the justices present is disqualified to sit in any case, one or more temporary justices may be assigned in accordance with RSA 490:3 or the remaining justices or justice shall hear and determine the case with all the power of the court.

33:4 **Expenses for Temporary Justices.** Amend RSA 490:18 by striking out said section and inserting in place thereof the following:

490:18 **Expenses.** They shall be entitled to receive their actual personal expenses when absent from home in the performance of their official duties, and to be reimbursed for money paid for office rent and for stenographic and typewriting service in the preparation and reporting of their opinions. A temporary justice shall be entitled to receive the same expenses and reimbursements, except for office rent, for the period of such service.

33:5 **Supreme Court Justices; Termination of Service.** Amend RSA 490:2, I (supp) as amended by striking out said paragraph and inserting in place thereof the following:

I. Any justice of the supreme court who shall become unable to perform his duties because of permanent disability shall be retired from regular active service on the bench. A justice who desires to retire because of inability to perform his duties shall certify to the governor and council his disability to perform his duties and shall furnish a like certificate of the chief justice; and the governor and council, if they find him unable to perform his duties because of permanent disability, shall order his retirement from regular active service. If a justice who is permanently disabled to perform his duties shall be unable or unwilling to certify his disability, the chief justice and 2 associate justices shall certify in writing his disability to the governor and council, who shall, if they find him, after due notice and hearing, unable to perform his duties because of permanent disability, order his retirement from regular active service. If the chief justice shall be unable to perform his duties, the requisite certificate may be furnished by the senior associate and 2 other associate justices. Any justice retired from regular service because of permanent disability shall receive the same benefits as he would have received had he retired at full retirement age; and such retirement shall terminate his service except as provided in RSA 490:3. The governor and council, upon retirement of any justice as provided herein, shall appoint his successor.

33:6 **Superior Court Justices; Termination of Service.** Amend RSA 491:2, I (supp) as amended by striking out said paragraph and inserting in place thereof the following:

I. Any justice of the superior court who shall become unable to perform his duties because of permanent disability shall be retired from regular active service on the bench. A justice who desires to retire because of inability to perform his duties shall certify to the governor and council his

394:17 Repeal. RSA 79:7 and 79:9, relative to the appeal board for forest taxation, are hereby repealed.

394:18 Effective Date. This act shall take effect 60 days after its passage.

[Approved June 22, 1983.]
[Effective Date August 21, 1983.]

CHAPTER 395 (HB 725)

AN ACT RELATIVE TO LIMITED ELECTRICAL ENERGY PRODUCERS.

Be it Enacted by the Senate and House of Representatives in General Court convened:

395:1 Definitions. Amend RSA 362-A by inserting after section 1 the following new section:

362-A:1-a Definitions. In this chapter:
I. "Cogeneration facility" means a facility which produces electric energy and other forms of useful energy, such as steam or heat, which are used for industrial, commercial, heating, or cooling purposes.
II. "Commission" means the New Hampshire public utilities commission.
III. "Limited producer" or "limited electrical energy producer" means a qualifying small power producer or a qualifying cogenerator, with a total capacity of not more than 5 megawatts.
IV. "Person" means any individual, partnership, association, corporation, governmental unit or agency or any combination thereof.
V. "Primary energy source" means the fuel or fuels used for the generation of electric energy, except that such term does not include the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, or control uses or the minimum amounts of fuel required to alleviate or prevent unanticipated equipment outages or emergencies directly affecting the public health, safety or welfare which would result from electric power outages.
VI. "Qualifying cogeneration facility" means a cogeneration facility which the commission determines meets such requirements, including requirements respecting minimum size, fuel use and fuel efficiency, as the commission may prescribe and 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.
VII. "Qualifying cogenerator" means the owner or operator of a qualifying cogeneration facility.
VIII. "Qualifying small power producer" means the owner or operator of a qualifying small power production facility.
IX. "Qualifying small power production facility" means a small power production facility which the commission determines meets such requirements, including requirements respecting fuel use, fuel efficiency and reliability, as the commission may prescribe and 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.
X. "Small power production facility" means a facility which produces electric 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 20 megawatts.

395:2 Exemption. Amend RSA 362-A:2 (supp) as inserted by 1978, 32:1 by striking out said section and inserting in place thereof the following:

362-A:2 Exemptions. Qualifying small power producers and qualifying cogenerators shall be exempt from all rules and statutes relative to electric utility rates or relative to the financial or organizational regulation of electric utilities.

395:3 Public Utility Purchases. Amend RSA 362-A:3 (supp) as inserted by 1978, 32:1 as amended by striking out said section and inserting in place thereof the following:

362-A:3 Purchase of Output of Limited Electrical Energy Producers by Public Utilities. The entire output of electric energy of such limited electrical energy producers, if offered for sale to the electric utility, shall be purchased by the electric public utility which serves the franchise area in which the installations of such producers are located.

395:4 Electric Rates; Disputes. Amend RSA 362-A:4 and 362-A:5 (supp) as inserted by 1978, 32:1 by striking out said sections and inserting in place thereof the following:

362-A:4 Payment by Public Utilities for Purchase of Output. Public utilities purchasing electrical energy in accordance with the provisions of this chapter shall pay rates per kilowatt hour to be set from time to time by the commission. Such rates shall be based on the purchasing utility's avoided costs. The commission may set long term rates which shall, at the option of the qualifying small power producer or qualifying cogenerator, be based on the purchasing utility's avoided costs either calculated for the time of delivery or calculated for a specified term at the time the qualifying small power producer or qualifying cogenerator agrees to be obligated to deliver for the specified term. Nothing in this section shall limit the authority of any electric utility or any qualifying small power producer or qualifying cogenerator to agree to a rate for any purchase which differs from the rate or terms or conditions which would otherwise be required by the commission.

362-A:5 Settlement of Disputes. Any dispute arising under the provisions of this chapter may be referred by any party to the commission for adjudication.

395:5 Optional Tax Exemption. Amend RSA 362-A:6 (supp) as inserted by 1981, 545:5 by striking out said section and inserting in place thereof the following:

362-A:6 Tax Exemption of Small Scale Power Facilities.
I. As used in this section, "small scale power facility" means any real or personal property used in the production of electric power by a qualifying small power production facility which uses water as a primary energy source, including the land, all rights, easements, and other interests thereto (excluding transmission lines from such facilities), and all dams, buildings, structures and other improvements situated thereon which are necessary or incidental to the production of power at the facility.
II. Any small scale power facility which begins commercial operation after August 29, 1981, may, at the option of the owner of such facility, be exempt from property taxation. If the owner of such facility elects to be exempt from taxation under this section, he shall enter into an agreement with the city or town in which the facility is located to make a payment in lieu of taxes. The payment shall be at least 2-1/2 percent, but not more than 5 percent, of the gross revenues of the facility in the preceding calendar year. Should the owner

of a small scale power facility and the city or town fail to agree on the percentage of gross revenues to be paid in lieu of taxes, the commission shall determine the percentage of gross revenue payable by the owner in lieu of property taxes. An exemption under this section shall be allowed for a period of 20 years.

395:6 Effective Date. This act shall take effect 60 days after its passage.

[Approved June 22, 1983.]
[Effective Date August 21, 1983.]

CHAPTER 396 (HB 739)

AN ACT RELATIVE TO THE CANCELLATION AND REFUSAL TO RENEW INSURANCE POLICIES.

Be it Enacted by the Senate and House of Representatives in General Court convened:

396:1 Insurance for Residents. Amend RSA 417-B:1, I as inserted by 1971, 453:1 by striking out said paragraph and inserting in place thereof the following:

I. Loss of or damage to real property which is used solely for residential purposes, which is owner occupied, and which consists of not more than 4 dwelling units.

396:2 Time For Cancellation. Amend the introductory paragraph of RSA 417-B:3 as inserted by 1971, 453:1 by striking out said paragraph and inserting in place thereof the following:

No insurer, after a policy has been in effect for 90 days, or if a policy is a renewal, effective immediately, shall cancel a policy except for one or more of the following reasons:

396:3 Cancellation; Refusal to Renew Time. Amend RSA 417-B:4, I as inserted by 1971, 453:1 by striking out said paragraph and inserting in place thereof the following:

I. State the date, not less than 45 days after the date of such mailing or delivery on which such cancellation or refusal to renew shall become effective, except that such effective date may be 10 days from the date of mailing or delivery;

(a) When the policy is being cancelled or not renewed for nonpayment of premium; or

(b) When the policy is being cancelled within 90 days of its effective date provided such policy is not a renewal.

396:4 Effective Date. This act shall take effect 60 days after its passage.

[Approved June 22, 1983.]
[Effective Date August 21, 1983.]

CHAPTER 397 (HB 810)

AN ACT RELATIVE TO LABELING AND BANNING OF CERTAIN PRODUCTS WHICH CONTAIN UREA-FORMALDEHYDE.

Be it Enacted by the Senate and House of Representatives in General Court convened:

397:1 New Subdivision. Amend RSA 339-A by inserting after section 7 the following new subdivision:

Products With Urea-formaldehyde

339-A:8 Urea-formaldehyde Foam Insulation. No person may manufacture or offer for sale in this state urea-formaldehyde foam insulation or a new home or mobile home containing urea-formaldehyde foam insulation.

397:2 Ban on Urea-formaldehyde Foam. Amend RSA 339-A by inserting after section 8 the following new sections:

339-A:9 Sales Prohibited. No person shall manufacture or offer for sale any new particle board or fiber board or housing unit or mobile home constructed of particle board or fiber board, containing urea-formaldehyde resin, without a written cautionary statement to the purchaser as set forth in RSA 339-A:10.

339-A:10 Cautionary Statement. The cautionary statement provided for in RSA 339-A:9 shall be printed in at least 10 point book face sans serif type and shall appear in all respects in the following form:

STATEMENT OF PRODUCT DISCLOSURE

THE PRODUCT (OR HOUSING UNIT) CONTAINS UREA-FORMALDEHYDE RESIN. FOR SOME PEOPLE UREA-FORMALDEHYDE MAY CAUSE HEALTH PROBLEMS SUCH AS IRRITATION OF THE EYES, NOSE, AND THROAT; COUGHING, HEADACHES, SHORTNESS OF BREATH, OR CHEST OR STOMACH PAINS. CHILDREN UNDER 2 YEARS OF AGE, ELDERLY PERSONS WITH BREATHING PROBLEMS OR PERSONS WITH ALLERGIES MAY HAVE MORE SERIOUS DIFFICULTIES. IF YOU HAVE A QUESTION ABOUT PROBLEMS YOU MAY HAVE WITH UREA-FORMALDEHYDE, CONSULT A DOCTOR.

339-A:11 Display of Statement.

I. A seller or manufacturer may incorporate the cautionary statement required by RSA 339-A:9 in a contract for sale with the purchaser. In such case, the cautionary statement shall appear in the contract immediately preceding the place in the contract for the purchaser's signature.

II. If the seller or manufacturer does not incorporate the cautionary statement required by RSA 339-A:9 within a contract for sale, the statement shall be printed on a label containing no other written material and attached to the fiber board, particle board, or housing unit or mobile home containing urea-formaldehyde resin.

397:3 Effective Date.

I. Section 1 of this act shall take effect upon its passage.

II. Section 2 of this act shall take effect January 1, 1984.

FEDERAL STATUTES

16 U.S.C. §824, PSNH Appendix Page 8, *infra*

16 U.S.C. §§824 (b) (1), (d) and (e), PSNH Appendix Page 9, *infra*

16 U.S.C. §824a-3 Appendix to Brief of Appellant at 148-152

16 U.S.C. §824a-3 (e) Appendix to Brief of Appellant at 149

STATE REGULATIONS

Puc §202.01 Requests for Commission Determinations.

(a) Except as provided in (b) through (m) below, any person seeking the action of the Commission shall do so by submitting a petition pursuant to Puc 203.

Puc §207.01 Declaratory Rulings.

(a) A person seeking a declaratory ruling on any matter within the jurisdiction of the commission shall request such ruling by submitting a petition pursuant to Puc 203.

(b) Such a petition shall be verified under oath or affirmation by an authorized representative of the petitioner with knowledge of the relevant facts.

(c) The commission shall dismiss a petition for declaratory ruling that:

(1) Fails to set forth factual allegations that are definite and concrete;

(2) Involves a hypothetical situation or otherwise seeks advice as to how the commission would decide a future case; or

(3) Does not implicate the legal rights or responsibilities of the petitioner.

(d) Except for a petition dismissed pursuant to subsection (c), the commission shall conduct an adjudicative proceeding on a petition for declaratory ruling in accordance with Puc 203.

of this Act [16 USCS §§ 791a et seq.] the Commission may be represented by the general counsel of the Commission (or any attorney or attorneys within the Commission designated by the Chairman) who shall supervise, conduct, and argue any civil litigation to which paragraph (3) of this subsection applies (including any related collection action under paragraph (5)) in a court of the United States or in any other court, except the Supreme Court. However, the Commission or the general counsel shall consult with the Attorney General concerning such litigation, and the Attorney General shall provide, on request, such assistance in the conduct of such litigation as may be appropriate.

(B) The Commission shall be represented by the Attorney General, or the Solicitor General, as appropriate, in actions under this subsection, except to the extent provided in subparagraph (A) of this paragraph.

(June 10, 1920, ch 285, Part I, § 31, as added Oct. 16, 1986, P. L. 99-495, § 12, 100 Stat. 1255.)

HISTORY; ANCILLARY LAWS AND DIRECTIVES

Explanatory notes:

The bracketed word "part" was inserted in subsecs. (d)(2)(B) and (d)(3)(B) as the capitalization probably intended by Congress.

Other provisions:

Application of section. For the application of this section generally, see Act Oct. 16, 1986, P. L. 99-495, § 18, 100 Stat. 1259, which appears as 16 USCS § 797 note.

CROSS REFERENCES

This section is referred to in 16 USCS § 825o-1.

INTERPRETIVE NOTES AND DECISIONS

16 USCS § 823b does not authorize FERC to assess civil penalty against unlicensed entity. Wolverine Power Co. v FERC (1992) 295 US App DC 343, 963 F2d 446, 22 ELR 21429.

REGULATION OF ELECTRIC UTILITY COMPANIES ENGAGED IN INTERSTATE COMMERCE

CROSS REFERENCES

This subchapter is referred to in 16 USCS §§ 803, 824a-3; 42 USCS § 7172; 43 USCS § 1761.

§ 824. Declaration of policy; application of Part

(a) Federal regulation of transmission and sale of electric energy. It is hereby declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this Part [16 USCS §§ 824 et seq.] and the Part next following [16 USCS §§ 825 et seq.] and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce. (1) The provisions of this Part [16 USCS §§ 824 et seq.] shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this Part [16 USCS §§ 824 et seq.] and the Part next following [16 USCS §§ 825 et seq.], over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

(2) The provisions of sections 210, 211, and 212 [16 USCS §§ 824i, 824j, and 824k] 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 [16 USCS §§ 791a et seq.] with respect to such provisions. Compliance with any order of the Commission under the provisions of section 210 or 211 [16 USCS §§ 824i or 824j], 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.

(c) Electric energy in interstate commerce. For the purpose of this Part [16 USCS §§ 824 et seq.], electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale". The term "sale of electric energy at wholesale" when used in this Part [16 USCS §§ 824 et seq.] means a sale of electric energy to any person for resale.

(e) "Public utility" defined. The term "public utility" when used in this Part [16 USCS §§ 824 et seq.] or in the Part next following [16 USCS §§ 825 et seq.] means any person who owns or operates facilities subject to the jurisdiction of the Commission under this Part [16 USCS §§ 824 et seq.] (other than facilities subject to such jurisdiction solely by reason of section 210, 211, or 212 [16 USCS §§ 824i, 824j, or 824k.]).

(f) United States, State, political subdivision of a State, or agency or instrumentality thereof exempt. No provision in this Part [16 USCS §§ 824 et seq.] shall apply to, or be deemed to include, the United States, a State or

FEDERAL REGULATIONS

OTHER AUTHORITIES

65 NH PUC 291

Even assuming that the majority's finding is based on a financial emergency, I cannot accept the "deficiency adjustment" of $552,178 to be charged annually over a 29-year period. This adjustment reflects approximately $1,022,611 of the rate increase granted. Staff witness Sullivan states he believes this amount should be removed because he maintains PSNH is seeking retroactive rate making. Public Service Company of New Hampshire counters that it has not sought to charge present or future ratepayers for benefits that were passed through previously.

I believe both Mr. Sullivan and PSNH are incorrect, based on the record before the commission. I believe that the exact impact relates to the service lives of the various plants in service. Since these components of plant vary in their initial service dates as well as their tax lives, I am not convinced that either position can prevail without a more thorough breakdown which has not been provided.

Re Public Service Company of New Hampshire

DF 80-116, Order No. 14,273
June 12, 1980

PETITION *by electric company for authority to increase its authorized common stock, $5 par value, from 18 million shares to 27 million shares; granted.*

Security issues, § 58 — Financing of construction program — Public interest.
An electric company was authorized to increase its authorized common stock, $5 par value, from 18 million shares to 27 million shares where the increase was found to be for proper corporate purposes, including the financing of the company's construction program, and was found to be in the public interest.

APPEARANCES: Frederick J. Coolbroth and Philip Ayers for the petitioner.

By the COMMISSION:

Report

By this unopposed petition, filed May 21, 1980, Public Service Company of New Hampshire (the "company"), a corporation duly organized and existing under the laws of the state of New Hampshire and operating therein as an electric public utility under the jurisdiction of this commission, seeks authority pursuant to RSA 369:14 to increase its capital stock beyond the amounts fixed and limited by its articles of agreement as follows: to increase its authorized common stock, $5 par value, from 18 million to 27 million shares.

At the duly noticed hearing on the petition, held in Concord on June 11, 1980, the company submitted that at a meeting of the common stockholders of the company held on April 8, 1980, the stockholders voted to amend the articles of agreement of the company to increase its authorized common stock to the higher amounts set forth in the company's petition, and a certified copy of the authorizing votes was submitted.

Company witness Lampron testified that the increases in the authorized capital stock were necessary for proper corporate purposes, including the financing of the company's construction program over the next several years.

Based upon all the evidence, the commission finds that the increase in the company's capital stock in the amounts requested in the petition for proper corporate purposes, including the financing of the company's construction program, will be consistent with the public good and should be approved and authorized. Our order will issue accordingly.

Order

Upon consideration of the foregoing report, which is made a part hereof; it is

Ordered, that Public Service Company of New Hampshire be, and hereby is, authorized to increase its authorized capital stock as follows: common stock, $5 par value, from 18 million to 27 million shares.

By order of the Public Utilities Commission of New Hampshire this twelfth day of June, 1980.

Re Small Energy Producers and Cogenerators

Intervenors: Energy Law Institute, Franklin Falls Hydro-Electric Corporation, Public Service Company of New Hampshire, Newfound Hydroelectric Company, New Hampshire Electric Cooperative, Inc., Legislative Utility Consumers' Council, New Hampshire Hydro Associates, Bethelhem Mink Farm Inc., Governor's Council on Energy, Concord Electric Company, and Granite State Electric Company et al.

DE 79-208, Fifth Supplemental Order No. 14,280
June 18, 1980

INVESTIGATION *on commission motion, of rates charged electric utilities for energy generated by small power producers; rates fixed.*

Rates, § 321 — Small electric energy producers and cogenerators — Avoided cost standard.
Avoided costs used in fixing rates charged to electric utilities for energy generated by small power producers should not be based solely on average fuel costs. [1] p. 296.

Rates, § 250 — Retroactive rates — Small power producers.
The statutes that allow for some retroac-

tive application of rates do not apply to small power producers since they are not designated as public utilities under either state or federal law. [2] p. 299.

Interstate commerce, § 79 — Federal and state regulation of small power producer rates — Charges to electric utilities.
Discussion of federal and state regulation of small power producer rates charged to electric utilities. p. 292.

Rates, § 321 — Small electric energy producers — Avoided costs.
Discussion of avoided costs used in fixing rates charged to electric utilities for energy generated by small power producers. p. 294.

APPEARANCES: Representative Eugene S. Daniell pro se; Peter Brown, Larry Smuckler, and Robert Olson for the Energy Law Institute; Robert Rowe for Franklin Falls Hydro-Electric; Philip Ayers for Public Service Company of New Hampshire; Joseph S. Ransmeier for Newfound Hydroelectric Company; John Pillsbury for New Hampshire Electric Cooperative; Gerald L. Lynch for the Legislative Utility Consumers' Council; Edward Forster, pro se; Charles A. Diamond, pro se; Gordon Marker for New Hampshire Hydro Associates; Robert C. Collman for Bethlehem Mink Farm, Inc.; Paul Ambrosino for the Governor's Council on Energy; Douglas MacDonald for Concord Electric Company; Philip H. R. Cahill and William G. Hayes for Granite State Electric; Gerald Beckman, pro se.

By the COMMISSION:

Report

I. Procedural History

On October 18, 1979, the commission on its own motion issued Order No. 13,869 (64 NH PUC 361), which initiated hearings under docket DE 79-208 pertaining to small power producers and cogenerators. Pursuant to NHRSA 363-A:4, Limited Electrical Energy Producers Act (LEEPA), and the Public Utility Regulatory Policies Act of 1978 (PURPA), Title II, § 210, this commission is empowered to determine a proper rate to be charged electric utilities for energy generated by a small power producer (SPP).

The commission devoted six hearing days for the presentation of testimony and exhibits from interested parties. The response to the commission's order was significant and positive as demonstrated by the list of appearances. These parties included a number of New Hampshire's present and potential small power producers, members of industry interested in small power production, representatives of various state and federal agencies, and representatives of the state's electric utility industry. Each sought to offer reasons for adjusting the present rate of four cents per kwh for energy and 4.5 cents per kwh for energy and capacity set by Order No. 13,589 in DE 78-232, DE 78-233 (64 NH PUC 82).

II. State Versus Federal Standards

The Public Utility Regulatory Policies Act (PURPA) sets forth a specific standard for determination of a proper small power producer's rate. This standard requires 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. This avoided cost standard has been the subject of various interpretations by the parties.

While PURPA has a defined standard, the state act, Limited Electrical Energy Producers Act (LEEPA), fails to provide any guidance or standard other than to require the commission to actively encourage the development of small scale and diversified sources of supplemental electrical power. RSA 362-A:1. As this commission has noted previously, the general overall theme of both legislative acts is to encourage the development of alternate energy generation.

The FERC regulations implementing § 210 of PURPA have eliminated any potential for conflict between these state and federal initiatives. According to these rules, the states are free pursuant to their own authority to enact laws or regulations providing for rates, which result in even greater encouragement of the alternate energy technologies. However, states cannot promulgate laws or regulations which provide rates lower than the federal standards. Such enactments would fail to provide the requisite encouragement for these technologies. Volume 45 — *Federal Register* No. 38, p. 12221 (February 25, 1980).

Further removal of any potential for conflict is provided in the FERC rules where state regulatory authorities are to be accorded great latitude in determining the manner of implementation of § 210. Volume 45 — *Federal Register* No. 38, p. 12230 (February 25, 1980).

The commission will generally adopt the avoided cost standard. However, due to the passage of LEEPA, the commission will recognize rates and measures where appropriate in excess of that allowed pursuant to the PURPA standard of avoided costs and the FERC rules. The only state statutory limitation as to allowance of rates in excess of avoided costs is that such an allowance can only be applied to facilities of five mw or less. Through this approach the commission will be in a position to honor the themes of both legislative enactments; namely, the rapid encouragement of alternate energy sources.

III. Energy Technologies Covered

Questions have arisen as to the applicability of the rate set in this proceeding to energy sources other than hydroelectric. Both PURPA and LEEPA are explicit as to the energy sources covered by the rates, rules, regulations and standards promulgated pursuant to the passage of each statute. Section 201 of PURPA defines a small power production facility as a facility which produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources or any combination thereof. Renewable resources have been further defined as including at a minimum wind, solar, and water.

Limited Electrical Energy Producers Act defines a qualifying limited electrical energy producer as one not involving the use of nuclear or fossil fuel. While LEEPA also has a capacity limitation different from that set forth in PURPA, the statutes are similar, in that the rate set covers small power producers using facilities with its primary source being biomass, waste, wind, solar, hydro, wood, or any combination thereof.

IV. Avoided Costs

Public Utility Regulatory Policies Act states that in setting rates, state public utility commissions must not set a rate that exceeds the incremental cost to the electric utility of alternative electric energy, PURPA § 210(b). Congress delegated to the Federal Energy Regulatory Commission (FERC) the task of rule making within the incremental cost guidelines. PURPA § 210(a). The FERC, in its rule-making function, has substituted the term avoided cost for the term incremental cost. However, the FERC defined avoided cost as the "incremental cost to an electric utility of electric energy or capacity or both which but for the purchase . . . such utility would generate itself or purchase from another source." 45 *Federal Register* 12234 (February 25, 1980). The commission therefore finds that the term avoided cost is another way of expressing the concept of incremental cost. For purposes of uniformity with the FERC rules, the commission will use the term "avoided costs" with the understanding that the use of the term equates to the concept of "incremental costs."

The FERC envisioned that commissions would use data provided by the electric utilities pursuant to § 133 of PURPA. While the FERC initially indicated that consideration of this data was mandatory in development of an avoided cost rate under § 210, the final FERC rules clearly establish that this information is but one of the factors to be considered. 45 *Federal Register* 12218 (February 25, 1980). If state commissions await the filing of § 133 data in November of 1980, the congressional intent to have alternative energy in service as quickly as possible will be thwarted. Furthermore, state commissions which await the filing of this data will be frustrated in their attempts to complete a § 210 review prior to March, 1981, the deadline established by § 210(f).

Since this commission established a procedure whereby the avoided costs are to be determined prior to the submission of § 133 data, the parties have offered a proxy as an appropriate substitute. The proxy offered is Public Service Company's most recently constructed and most efficient oil generating station, Newington. Upon review, the commission finds that the proxy is reasonable as a starting point and that suitable adjustments can be made to arrive at the avoided costs for Public Service Company. (PSNH)

The parties, while in agreement as to the Newington proxy, differ substantially in the components to be considered in arriving at the incremental cost or the avoided costs at the margin. Public Service Company of New Hampshire has offered the average fuel cost at Newington for six months ending June 30, 1980, 47.4 mills. Public Service Company of New Hampshire has estimated the average 1980 fuel cost to be 52.7 mills. As to adjustments for operation and maintenance costs and inventory costs, PSNH contends that such costs are fixed and therefore should be excluded for purposes of calculating avoided costs. Additionally, PSNH argues that consideration should be given to the change that will occur in PSNH's avoided costs with the advent of Seabrook.

Granite State Electric (GSE) has adopted a similar approach. Granite State Electric Company stated that its average fuel costs as of December, 1978, was 28 mills and that as of December, 1979, this figure had increased to 48 mills. No GSE estimates were provided

for 1980. Granite State offers the additional argument that it deserves additional consideration because of its present state of excess capacity. A GSE witness testified that its supplier of energy and capacity, New England Power, would not be in need of additional capacity until 1993.

Staff economist, Lisa Gertler, rejected the proposition that avoided costs should be solely based on fuel. While witness Gertler calculated a fuel component based upon the assumption that oil-fired electricity would be displaced, she also included calculations for other costs that would be avoided, inventory and operation and maintenance costs. Additionally, her calculations included a formula for calculating the additional value of a purchase from a small power producer which can meet an utility's daily peak loads thereby displacing the highest marginal cost generating sources.

Ms. Gertler agreed with the commission's prior determination of five mills as an additional allowance for those units that can provide capacity as well as energy. Due to the financing problems experienced by small power producers, Ms. Gertler recommended that in addition to setting a rate, the commission provide a long term incentive by "grandfathering" small power producers at the determined rate as the come on line. An additional recommendation was to instruct utilities to accept any contractual agreement offered by a small power producer unless the utility can prove unjust and unreasonable terms.

The following table illustrates Ms. Gertler's recommendation for avoided costs ending June 30, 1981:

Base Fuel Cost	61.81 mills per kwh
Adder for Daily Peak	6.18
Correction for Forced Outages	4.33
Inventory Cost	1.89
Operation and Maintenance	2.10
Total	76.31 mills per kwh

The total for energy and capacity would be 81.31 mills per kwh.

The Energy Law Institute (ELI) has provided substantial background into the legal and economic factors associated with setting a rate pursuant to § 210 of PURPA. Energy Law Institute witness Martin Ringo offered similar adjustments to the basic fuel component:adder for incremental cost differences from Newington, a correction for forced outages, operating and maintenance expenses and inventory cost. In addition, ELI cites the commission's attention to other components of avoided costs such as physical depreciation and externalities, which are unquantifiable on the basis of this record but nonetheless are argued to exist.

The ELI agrees with the quantifiable components found by staff with one exception, the adder for incremental cost differences from Newington. Stating that the staff projection is conservative ELI offers an adder of 10.82 mills per kwh in lieu of staff's 6.18 mills per kwh. Energy Law Institute proposes the adjustment in the first instance on the basis that Newington is PSNH's most efficient oil burning unit and as such it will be the first company-operated oil unit on line under NEPOOL's economic dispatch system. Therefore, according to ELI when Newington is not on line because of either scheduled or unscheduled outage or when system demand exceeds capacity with only Newington and more economic units on line, the avoided cost will exceed the base fuel cost of Newington. Energy Law Institute's proposal differs from staff's in that consideration is given to the Schiller station and PSNH's NEPEX purchases.

Numerous existing and potential power producers testified at the hearings. One of the most complete offerings came from Newfound Hydroelectric Company. While in general agreement with the approach offered by Ms. Gertler, Newfound requests a rate of 80 mills per kwh for energy and 85 mills for units which can provide both energy and capacity.

While in disagreement with the narrow interpretation offered by PSNH and GS as to avoided costs, Newfound has applied recent increases in the price of oil to indicate the impropriety of the figures offered by the two aforementioned utilities. Newfound highlights the PSNH projection for 1980 which reveals a 27.3 per cent increase in the last six months of 1980. Applying this increase to the first six months of 1981, Newfound arrives at a rate of 70.9 mills per kwh under PSNH's scenario. Turning to Granite State's figures, Newfound focuses on the 75 per cent increase between December, 1978, and December, 1979, which carried forward to December, 1980, would yield a cost rate of 83.8 mills per kwh.

Another thorough presentation was provided by Gordon Marker of New Hampshire Hydro Associates. Mr. Marker has significant experience in the field of hydroelectric generation. Mr. Marker focused on the tremendous front end costs associated with small power projects. An observation supported by Dr. Gerald Beckman, Ted Larter, and Edward Forster. Mr. Marker offered that the commission should adopt a flexible approach and suggested that those small power producers familiar with utility accounting, ratemaking, and regulation should be treated as in essence a small utility.

Representative Eugene Daniell, the major proponent of LEEPA, cites our attention to the inability of small power producers to hire the necessary lawyers and accountants if the commission should proceed to set rates on a project by project basis. The real question according to Representative Daniell is what is necessary to increase the amount of alternate energy in the state. Representative Daniell asks the commission to consider the real costs of Seabrook if it should decide to adopt the approach of using the next plant on line.

The LUCC urges the commission to avoid overestimation of avoided costs. In particular, the LUCC suggests that there is not an adequate record for the inventory and operation and maintenance adjustments offered by staff witness Gertler.

Commission Analysis

[1] The position that avoided costs should be based solely on average fuel costs is rejected. The FERC rules clearly state that a determination of the avoided costs as to energy purchased from small power producers envisions costs in addition to fuel and operating and maintenance. Volume 45 *Federal Register* 12225 (February 25, 1980). The examination of a particular oil-fired generating station's fuel price cannot cease at the price of the fuel. A generating station like Newington represents the avoided fuel cost only when the plant is on line and only when following the system's load. It is necessary to develop an appropriate adder to reflect a purchasing utility's cost when the above two factors are not operative.

As to the development of an appropriate adder to the fuel cost, the commission will accept staff's adjustment. This adjustment is based on a formula which multiplies the factor for costs above Newington by the percentage of time the load exceeded Newington by the probability of such load being supplied by the small power producer. While there may be merit to the considerations offered by ELI as to other plants and system purchases, the record has not been significantly developed to measure the accuracy of the projections.

The fuel cost to which the adder is applied is the projected average price of a barrel of oil for Newington for the period July 1, 1980, to June 30, 1981. Recent activity by the oil producing nations together with past underestimations by PSNH indicate that the figure used is conservative.

The adjustment for forced outages is also accepted. Recent hearings in the fuel adjustment cases, DR 80-46, establish the existence as well as the frequency of these adjustments. These forced outages raise average avoided cost because a utility is required to substitute less economical units. The staff correction of 7 per cent for the unscheduled outage rate at Newington and the weighted cost of all units more expensive than Newington is justified.

The adjustment for inventory has been challenged on the basis that the amount of energy provided by the small power producers is so minute as to not be a factor in inventory. The commission finds that in theory the adjustment for inventory is justified. While the number of small power producers may very well impact on inventory, there is no question that this cost is an avoided cost. Since the rate set in this proceeding will encourage the development of alternative energy sources both in quantity and quality, to ignore this aspect of avoided cost would support circularity and frustrate the purpose of both PURPA and LEEPA. The staff adjustment based on the working capital component associated with financing fuel inventory divided by the corresponding annual output of the plants involved, is a reasonable method for approximating fuel inventory costs.

Staff's proposed adjustment for operation and maintenance expenses does not distinguish between fixed and variable expenses. While consistency may dictate a removal of certain fixed costs, it is equally clear that recognition must be provided for physical depreciation as suggested by ELI. Since the record does not reveal these subtle and possibly balancing adjustments, the commission will accept the adjustment proposed by staff.

The discussion up to this point has focused upon a small power producer selling strictly energy. However, when a small power producer can provide reliable capacity as well as energy, the avoided costs are higher. This additional benefit has been clearly recognized by this commission in its prior report and Order No. 13,589 (64 NH PUC 82) and the FERC in its recent promulgation of rules. Volume 45 *Federal Register*, 12216, 12225 (February 25, 1980).

The testimony in this proceeding as well as the former case has revealed the accuracy of a five mill adjustment for capacity. The criteria used in our previous report and order is again adopted. While § 292.304(c) indicates that there are valid reasons for adopting different criteria for capacity adjustments depending on the alternative energy source used by the small power producer, there is not enough evidence in this record to adopt any further refinement.

The testimony of witnesses Larter, Harris, Forster, Marker, Beckman, Ambrosino, and Gertler all focus on a major problem faced by all small power producers, namely financing. Financial institutions do not have the necessary experience under either PURPA or LEEPA to properly evaluate the financial strength of a given project. Concern has been raised that the rate today may be lowered in the future which in turn would alter the economics and financial attractiveness of the projects. The record establishes the need to set not only a fair rate but some assurance that the rate will continue into the future.

Another factor that enters into this analysis is the next scheduled plant, Seabrook I. Substantial amounts of testimony and exhibits were devoted to answering the question of whether avoided costs will increase or decrease with the introduction of Seabrook I into the generation mix. Upon a review of the record it is simply impossible to forecast the effect Seabrook I will have on avoided costs of PSNH or GSE. While witnesses from these utilities initially used a total cost of $2.6 billion for completion of Seabrook I and II, this figure was later raised to $3.1 billion. Public Service Company of New Hampshire's most recent report to the commission raises the figure to $3.3 billion. This figure does not include decommissioning costs, nuclear waste storage costs, or additional costs resulting from the aftermath of Three Mile Island or the slowdown in construction. On a mills per kwh basis, certain assumptions are made as to the useful life of the plants, the outages, the system load as well as other factors that given different assumptions could change the mills per kwh rate. However, it is also clearly established that oil prices are rising at a phenomenal rate exceeding the consumer price index and fueling the fires of inflation. The differential between oil fuel costs and nuclear fuel costs continues to widen.

Whether or not the avoided costs of PSNH's system are more or less than the present with the advent of Seabrook depends largely on the assumptions made. While the commission has found the economics of Seabrook justify its construction, the impact of its construction on avoided costs in 1983 and beyond is not clear.

Because of the commission's concern that alternative energy be developed as quickly as possible, coupled with our recognition that the advent of Seabrook places an entirely new variable into the avoided cost calculation, the commission finds that the rate set in this proceeding will be applicable as a minimum to all small power producers presently operating qualifying facilities and to all small power producers who activate qualifying facitilites between the date of this order and the date of initial generation at Seabrook I, for the life of the qualifying facilities. In essence, those small power producers, with qualifying facilities either under PURPA or LEEPA, will be grandfathered to the rate set in this proceeding as a minimum if the qualifying facility begins generation prior to electrical generation at Seabrook I.

The rate grandfathered for the aforementioned qualifying producers is the staff proposal of 7.631 cents per kwh for energy and 8.131 cents per kwh rounded upwards to 7.7 cents and 8.2 cents respectively to account for the conservative assumptions taken by staff and the unquantified externalities.

This rate will be applicable to all New Hampshire utilities, except for Granite State. Due to the commission finding that Granite State has excessive capacity, the commission for the present will only award the energy component of 7.7 cents for all kwh sold to Granite State by qualifying small power producers within its service territory.

In terms of application of the aforementioned rates to cogenerators, the commission is mindful of the fact that no cogenerator or party interested in cogeneration appeared in our proceedings. The aforementioned rates for energy and capacity will only apply to (1) cogenerators who offer to sell their entire output and buy back all their needs, (§ 292.304b) and (2) as to electrical generators utilizing portions of their own output and selling excess to the electric utility only the energy rate will apply minus the adder for daily peak or seven cents. The remainder of the cogeneration question will be resolved in subsequent hearings.

As each new small power producer is connected to a New Hampshire utility, an adjustment will be made to reflect any increased costs in the utility's basic rates or fuel adjustment.

Finally, although the commission sets a minimum today, such a finding does not foreclose additional increases in the future prior to Seabrook I. While the commission is prepared to have additional hearings in the future due to increased avoided costs, the commission does not have the resources or the capabilities to begin treating small power producers as utilities. Besides the strict prohibition as to such treatment in both PURPA and LEEPA, it would be impossible at this moment in regulation to begin seeking out comparable small power producers so as to apply the traditional cases of Hope and Bluefield to arrive at a reasonable return on common equity. While the idea has long term merit, the practicality of regulation forecloses use of this method.

V. Existing Producers and Effective Date

[2] The question has been raised as to whether or not it is fair to allow existing small power producers the new rate. Various parties have contended that an allowance of this new rate to existing small power producers will be a major windfall. Small power producer, Ted Larter, reacted by stating that to do otherwise would punish the highly skilled small power producer who achieved results before lesser talented or motivated small power producers began their operations. The question is resolved by examination of the FERC rules that clearly provide guidance that if the choice is between small rate reductions and help to the small power producer, the latter should prevail.

The commission does not examine the rate of return earned by other suppliers of energy to utilities. This factor together with the legislative restrictions on treating these small power producers independent of the regulatory system but for pricing purposes, is of significant rationale to allow the rate found in this proceeding to be applied to existing small power producers.

There has been some discussion that the rates be applied retroactively to May

1, 1980. The small power producers are not designated as utilities under either state or federal law. Consequently, the statutes that allow for some retroactive application of rates do not apply. Therefore, the aforementioned rates will apply to all energy-capacity as of June 18, 1980, forward. Our order will issue accordingly.

Supplemental Order

Upon consideration of the foregoing report, which is made a part hereof; it is hereby

Ordered, that all qualifying small power producers will receive 7.7 cents per kwh for all energy sold to any New Hampshire electric utility, and it is

Further ordered, that all qualifying small power producers will receive 8.2 cents per kwh for reliable capacity provided to any New Hampshire electric utility except Granite State Electric, and it is

Further ordered, that qualifying cogenerators are only included to the extent discussed in the report, and it is

Further ordered, that all electric utilities within the state provide quarterly information as to amount of kwh's purchased from small power producers,

By order of the Public Utilities Commission of New Hampshire this eighteenth day of June, 1980.

Re Public Service Company of New Hampshire

DE 80-57, Order No. 14,282
June 20, 1980

PETITION *by electric company for authority to acquire an easement over private land to be used for transmission lines, and to determine a fair and reasonable price to be paid for the easement; damages fixed and awarded.*

Eminent domain, § 8 — Acquisition of easement — Award of damages.
An award of damages for an electric company's acquisition of an easement for the construction of transmission lines was based upon the testimony of the company's witnesses rather than upon the testimony of the landowner's witness.

APPEARANCES: Eaton W. Tarbell, Jr., for the Public Service Company of New Hampshire; Steven Ells for Olde Mill Investments, Inc.

By the COMMISSION:

Report

The Public Service Company of New Hampshire, a public utility engaged in

the supply of electric service in the state of New Hampshire, pursuant to provisions of RSA 371, petitioned the Public Utilities Commission of New Hampshire for permission to acquire a perpetual rights of easements to certain lands in an area of Hampton, New Hampshire, said lands to be used in conjunction with transmission lines emanating from the Seabrook nuclear power station; and further to determine damages to be paid for same. The petition was filed on March 7, 1980, with a duly noticed public hearing scheduled for May 13, 1980, subsequently adjourned until May 22, 1980, at 2:00 P.M..

The petition prayed that the commission determine that the necessity for the taking had been predetermined through prior approvals by state and federal authorities under RSA 162-F et al. It further sought that the commission determine a fair and reasonable price to be paid for said easement.

The question of necessity was resolved early in the proceeding with a ruling that issue of a certificate of site and facility plus approval by the Nuclear Regulatory Commission precluded further challenge. The matter of value was the only item remaining, and to this end, the petitioner presented two witnesses. The landowner presented one witness.

Petitioner's witness, Harry R. Murray, provided the commission with maps and plans on which the property in question was isolated. These were entered as Exhs P-1 and P-2 respectively.

Petitioner's witness, David F. Colt, indicated that he had appraised the property before the taking at $82,000 and after the taking at $64,400, resulting in damages of $17,600. Supporting these appraisal figures were several photographs entered as exhibits, w the location of the photographer mark upon Exh P-2 for each view. The taki involved property which included in a dition to the land a two-family resider with an attached barn plus the founc tion of a former garage. Mr. Colt a vised the residence had been unoccupi for an extended period and the gara had been mostly destroyed by fire so three years prior. It was revealed tl the bulk of the property in question w zoned residential, while a small porti . . . 0.687 acres located under an existi power line right of way was zoned dustrial. Mr. Colt considered the inco potential of the two-family home to sess its value before and after the takin He considered fair rental of the t units at a total of $540 per month a examining this with similar sales timated a value of $59,400 for the ho with one acre of land which he valued $15,000. He considered the additio 14 acres valued at $22,500 for a to value of the home and land of $82,0 He supported this estimate with data comparable sales in the Hampton ar He arrived at these under both a mar data approach and an income data a proach. He attributed all damages to t taking of the land, with no impact on t building. His damages include $10,4 for the land and $7,200 in severar damages.

In support of the landowner, Geo H. Sumner, testified on the basis of t lots as shown in the tax maps of t town of Hampton (Map 350, Lots 3 a 4). For Lot 3, Sumner appraises value as $20,500 before the taking a zero after the taking. He claims pot tial industrial use and based his praisal upon comparable industr sales. For Lot 4, Mr. Sumner claime value before the taking of $100,000. T ways within thirty (30) days of the date of this Order; and it is

FURTHER ORDERED, that upon the removal of rails as authorized herein the crossbuck and advance warning signs at the said crossings shall be removed by the agency responsible for their maintenance.

By order of the Public Utilities Commission of New Hampshire this eighteenth day of June, 1982.

Re Belmont Sewer Commission

Intervenor: Town of Belmont

DE 82-131, Order No. 15,713
June 18, 1982

ORDER *granting an easement to a local sewer commission for the installation of plant crossing state-owned railroad tracks.*

APPEARANCES: David Caron, town administrator, for the Town of Belmont, and Richard Fournier, chairman of the Belmont Sewer Commission.

By the COMMISSION:

REPORT

On April 27, 1982, the Town of Belmont, New Hampshire, through its Sewer Commission, petitioned this Commission for an easement to install by the open cutting method 30 feet of 30" sleeve at Station 1241 + 42± (Railroad Stationing) in the Town of Belmont, New Hampshire. It is noted that earlier approval had been sought and granted under DE 81-85 for several crossings (See Order No. 14,876 April 30, 1981 [66 NH PUC 177].) The third of the six crossings granted by said Order was to have been at the Fox Hill Road Crossing in Belmont. The instant petition indicates that the crossing now being sought replaces the one originally planned for Fox Hill Road.

On April 28, 1982, the Commission issued an Order of Notice setting the matter for hearing at 10:00 a.m. on June 9, 1982. Notices were sent to the following: Richard Fournier, Chairman, Belmont Sewer Commission (for publication); John Bridges, Director, Safety Services; Selectmen's Office, Town of Belmont; George Gilman, Commissioner, Department of Resources and Economic Development; N.H. Transportation Authority; and the Office of Attorney General.

The public hearing was convened as noticed, with Hearing Examiner, Michael W. Holmes presiding. At the outset,

concern was expressed that notice being given to the defunct New Hampshire Transportation Authority may not have reached the proper authority now handling State railroad affairs. Telephone calls to the Department of Public Works and Highways, did, in fact, reveal that the notice had not been received by the railroad administrator, but it was confirmed that no objections to the crossing existed and that Highway had been dealing with the Water Supply and Pollution Control Commission on the same matter.

With notice problems resolved, the hearing proceeded. Mr. Fournier discussed the petition and how this would replace the Fox Hill Crossing earlier approved.

No intervenors were present, nor were there any written objections. Accordingly, the Commission finds the granting of the easement for the purpose of crossing State-owned railroad tracks in Belmont, New Hampshire as described herein in the public good. Our Order will issue accordingly.

ORDER

Upon consideration of the foregoing Report, which is made a part hereof; it is

ORDERED, that authority be granted to the Belmont Sewer Commission to cross under public lands in the Town of Belmont, New Hampshire as outlined in the attached Report and petitioner's exhibits; and it is

FURTHER ORDERED, that authority granted by so much of Order No. 14,876 referring to a crossing at Fox Hill Road be, and hereby is, withdrawn.

By order of the Public Utilities Commission of New Hampshire this eighteenth day of June, 1982.

Re New England Electric Transmission Corporation

Intervenors: Powerline Education Fund et al.

DSF 81-349. Second Supplemental Order No. 15,715
48 PUR4th 477
June 22, 1982

APPLICATION *of electric transmission corporation for a certificate of site and facility to construct, operate, and maintain an electric transmission line; corporation held to have met its burden of proof on the "need for power" issue.*

Certificates, § 76 — Factors affecting grant or refusal — Transmission lines — Burden of proof.

To meet a "good cause" requirement for a certificate of site and facility, an electric transmission corporation seeking to construct new transmission lines was required to establish each element of the "need for power" issue by a fair preponderance of the evidence, not by clear and convincing evidence; therefore, the company only had to prove that each proposition it introduced was more likely to occur than not. [1] p. 413.

Certificates, § 76 — Factors affecting grant or refusal — Certificate for transmission line — Application of burden of proof.

In determining how to apply an electric transmission company's burden of proof requiring it to meet a preponderance of the evidence standard to build a transmission line, the commission held that the company's testimony must be viewed in a light favorable to the company, and unless the testimony was incapable of belief or internally contradictory, the commission would accept the testimony as reasonable predictions and estimations of what might occur in the future. [2] p. 413.

Certificates, § 76 — Factors affecting grant or refusal — Certificate of site and facility — Defining "electric power" and "demand."

In determining whether to grant a certificate of site and facility, the commission held that the fact that a proposed facility would deliver energy and related cost savings and not capacity to a given geographical area was immaterial to the issue of whether the facility met the demand for electric power since the phrase "meet the present and future demand for electric power" was interpreted by defining the term "electric power" to include energy (the ability to do work over a period of time) and capacity (the capability of providing energy at any given instant in time); furthermore, "demand" was interpreted in its economic sense (the amount of electric energy or capacity that buyers will buy at specified prices during given periods of time) and its engineering and planning sense (the amount of electric energy or capacity that the system will be called upon to deliver or have available in a given period of time). [3] p. 414.

Certificates, § 76 — Factors affecting grant or refusal — Certificate of site and facility — Burden of proof requirement satisfied.

In an intermediate step of the proceedings for a certificate of site and facility, an electric transmission corporation seeking to build an 83-mile transmission line was held to have met its burden of proof in the need for power issue by showing the likelihood of surplus energy from another line, the projected load growth for the geographical area, and the savings generated by the transmission line. [4] p. 417.

By the COMMISSION:

OPINION

This matter involves the application of the New England Electric Transmission Corporation ("NEET") for a certificate of Site and Facility to the Bulk Power Supply Site Evaluation Committee (SEC) and the Public Utilities Commission of the State of New Hampshire. The question presented to this Commission at this stage in the proceedings is whether NEET has met its burden of going forward with sufficient evidence to establish that a transmission line with approximate voltage specifications of ±300 KV and a capacity of 690 MW extending 83 miles from the Quebec-New Hampshire border to Comerford Station, Grafton County, New Hampshire or a shorter transmission line of 6.7 miles from the Vermont border at Moore Station to Comerford Station, New Hampshire, is required to meet the present and future demand for electric power within the meaning of RSA 162-F:8(b).

The Commission, at this stage of the proceedings, finds that NEET has met its burden of going forward on this issue. The Commission emphasizes that it is *not* deciding at this stage whether one party's evidence outweighs another party's evidence on the issues relating to the "need for power." That process of weighing and balancing will occur when the entire record in this proceeding is closed. Indeed the intervenors, the Powerline Education Fund (PEF) and others, and the Attorney General as counsel to the public will have full opportunity and will be expected to respond to the applicant's evidence at subsequent hearings.

I. *PROCEDURAL HISTORY*

On November 13, 1981, NEET filed with this Commission an application for a certificate of Site and Facility to construct, operate and maintain an electric transmission line in Coos and Grafton Counties, New Hampshire. The application was filed pursuant to RSA 162-F. In brief, the application sought approval and a certificate for one of two alternate lines. The first line would extend 83 miles from Tabor Notch in Pittsburg, New Hampshire to a converter site south of Comerford Station. The second line would enter New Hampshire from Vermont at Moore station and run 6.7 miles to the converter site at Comerford Station. (Application pp. 3-5, 8-9). The application stipulated a design voltage of ±450 KV, with a carrying capacity of 2000 MW operating on direct current for either alternative. (Application pp. 2-3).

On November 25, 1981, the SEC and this Commission pursuant to RSA 162:7 met jointly to consider the application and scheduled an informational hearing on the application in Littleton and Lancaster, New Hampshire on December 22, 1981. Informational hearings were subsequently held in Littleton and Lancaster on December 22, 1981 and in Lancaster and Littleton on January 14 and 15, 1982.

Adversarial hearings commenced on February 18, 1982 in Littleton. Subsequent hearings were held in Colebrook, March 4, 1982; in Concord on March 18 and 19, 1982; in Concord, April 15 and 16, 1982; and in Concord, April 22 and 23, 1982. At the April 23, 1982 session counsel for NEET stated that it had completed its case in chief on the issue of the "need for power." (T. 14-167, T. 15-133).

During the course of the hearings two motions of particular relevance to this matter, were filed with the SEC and this Commission. On December 29, 1981 the PEF, a group with full party status in this proceeding moved to recuse Commissioner McQuade of the Public Utilities Commission. On December 31, 1981, the Attorney General, as statutorily appointed representative of the public, also moved to recuse Commissioner McQuade and on January 18, 1982 moved to have a special commissioner appointed under RSA 363:20. Commissioner McQuade subsequently excused himself from these proceedings and the Governor and Council nominated and approved Richard J. Daschbach to sit as special commissioner in place of Commissioner McQuade.

PEF also moved on February 16, 1982 to consider Phase II of the proposed transmission line with Phase I. NEET, in its application, had stated that its proposed transmission line (each alternate) was designed at ±450 KV and 2000 MW of capacity in the event that sufficient power would be available from Quebec in the early 1990's to warrant additional transmission line construction from Comerford Station through New Hampshire to the New Hampshire-Massachusetts border. NEET referred to the onstruction of each alternate proposed ı its application as Phase I and referred › the additional transmission line south ·om Comerford Station to the Massa- husetts border as Phase II. NEET stated ıat if and when Phase II became viable would make application to the SEC nd this Commission for a certificate of te and facility under RSA 162-F for hase II. NEET stated, however, that the esign of the proposed Phase I alter- ates at the higher voltage of ±450 KV at 000 MW was in contemplation of the onstruction of Phase II, if and when hase II were warranted. NEET wit- esses also testified that if Phase II were ever built, the Phase I alternates could e built at design ratings of approxi- ıately ±300 KV and 690 MW. NEET bjected to the PEF motion to join Phase : with Phase I and the SEC asked for riefs and argument on the issues raised. ›n April 23, 1982 at the close of the pplicant's case on the "need for power" sue, the SEC and this Commission :ted on the PEF motion to join Phase I ıd Phase II. The PEF motion was ranted in part and denied in part, (T. 5-113-115), by a ruling requiring NEET › submit an application on Phase II if it roceeded with Phase I at ±450 KV and)0 MW. The SEC and the Commission so ruled that if NEET wished to go ›rward with the proposed alternates at 300 KV there was no integration and it eed not file an application on Phase II. he SEC also referred to this Commis- on the question of whether NEET had ıet its burden of proof[1] as to the "need ›r power", invited the parties to brief ıe issue and requested this Commission › act expeditiously in deciding the issue. [. 15-127-128). NEET excepted to the ruling of the SEC and the Commission (T. 15-133-134). Since the ruling on April 23, 1982, NEET has not filed an application on Phase II nor amended its present application to cover Phase II. Accordingly, the issue before this Commission is whether NEET has met its burden of proof on the "need for power" issue with respect to the two alternates at a proposed design of approximately ± 300 KV and 690 MW.

II. *ISSUES PRESENTED*

On April 27, 1982 this Commission established a briefing schedule for the parties and directed their attention to specific questions to be addressed in the briefs. These specific questions are as follows:

"1. What should be the burden NEET should meet on need for power as to this docket?

"2. Is the burden different for the proposal of 6.4 miles (sic) vis-a-vis the proposal for 83 miles?

"3. Should the Commission make its determination as to need for power using criteria for: (a) New Hampshire only; (b) New Hampshire and New England; or (c) New England only?

"4. Does the burden of proof change pursuant to an energy banking concept vis-a-vis an energy surplus scenario?"

The Commission has received initial and reply briefs from NEET, PEF and the Attorney General as counsel for the public.

[1]The parties have characterized the issue as one of rden of proof. Technically the issue is whether NEET has :t its "burden of going forward". However, for consistency with terminology used in the SEC Order and briefs of the parties we will refer to the burden as the "burden of proof."

A. *What Is The Standard to be Applied to NEET's Burden of Proof on the Need for Power Issue and the Proposed Alternate Routes?*

[1, 2] Before determining whether NEET has met its burden of proof on the need for power issue, this Commission must first determine the standard to be applied. The Commission finds that NEET must establish each element of the "need for power" issue by a fair preponderance of the evidence. By a fair preponderance of the evidence, we mean that the evidence introduced must establish that the proposition to be proved is more likely to occur than not. In determining whether a fair preponderance of the evidence exists with respect to each element, the Commission finds that the evidence must be viewed in a light favorable to the party with the burden.

This Commission must note that this is an administrative proceeding. While it bears some resemblance to civil judicial proceedings there are important differences. First, strict rules of evidence are not applied, especially hearsay rules. Second, most testimony and documentary evidence will be expert testimony or exhibits based on the expertise of the witness sponsoring the exhibit. Third, the problems associated with drawing inferences from eyewitness accounts of past behavior or events are virtually nonexistent in these types of proceedings.

This Commission and the SEC is almost always confronted with expert testimony from qualified witnesses. Uncertainty associated with such evidence arises because the witnesses and exhibits attempt to predict with reasonable certainty events which may or may not occur in the future or the effects of environmental phenomena over long periods of time where data are uncertain, conflicting or non-existent. Recognizing these characteristics of these proceedings, this Commission must test NEET's case in chief on the "need for power" issue.

The Supreme Court of New Hampshire has held that the standard for measuring the burden of proof in rate making procedures before this Commission is the "preponderance of the evidence" standard. Legislative Utility Consumers' Council v New Hampshire Pub. Utilities Commission (1977) 117 NH 972, 974, 23 PUR4th 128, 380 A2d 1083. Professor Davis in his treatise on administrative law states that the standard, absent special public policy considerations compelled by statutory language or constitutional mandate, is the standard of the preponderance of the evidence. 3 Davis, Administrative Law Treatise § 16.9 (1980). Given this body of authority we find that the applicable standard in this matter is the preponderance of the evidence.

PEF urges that a different standard be applied to this case. Its argument is based on RSA 162-F:6. That provision requires an applicant for a certificate of site and facility to have complied with RSA 162-F:4 prior to filing the application. RSA 162-F:4 requires utilities to file annually their long-range plans for bulk power facility construction and retirement. RSA 162-F:6 requires that facilities for which certificates are requested be taken from the inventory of facilities described in the utility's long-range plans unless the applicant can show good cause as to why the facility was not included in the long-range plans.

PEF correctly points out that the facilities for which NEET has requested a certificate were not part of NEET's long-range plans and were not part of the ıventory maintained by NEET or its ffiliated companies under RSA 162-F:4. EF then argues that because NEET ıust show good cause why the proposed ıcilities were not included in or selected ·om the inventory to be maintained ursuant to RSA 162-F:4, NEET must ıeet its burden of proof on the need for ower issue under a standard of "clear nd convincing" evidence.

An analysis of the statute persuades s that the "good cause" requirement oes not elevate the burden of proof of 'EET to a standard of clear and conincing evidence. On the contrary, the good cause" requirement is a legal :quirement that the applicant must ıeet in addition to the other legal reuirements of the statute. As a separate :gal requirement or condition for obıining a certificate of site and facility, ıe "good cause" requirement has no earing on the burden of proof stanard. Indeed, upon final disposition of ıe application in this docket, NEET ıust establish good cause before it can e awarded a certificate. Whether NEET as or has not shown "good cause" ithin the meaning of RSA 162-F:6 is ot before us at this stage of the pro:eding. Accordingly, we do not rule on ıis issue except insofar as PEF urges ıat the "good cause" bears on the andard to be applied in assessing the urden of proof.

Based on our determination that the ɔplicant's burden of proof is to estabsh each element of the need for power y a preponderance of the evidence, we ıust now describe how that standard is › be applied to the evidence submitted y NEET in its case in chief. As we noted ırlier, unlike civil judicial proceedings, e are not confronted by testimony and ʼidence as to the legal significance and ıferences to be drawn from such evidence with respect to past events. On the contrary we have testimony by Mr. Robert O. Bigelow and Mr. Roland H. Lalande, two qualified experts in their fields, as to the probability of events happening in the future and the relationship of the proposed facility to these events. Under the circumstances and for purposes of ruling on the issues at this stage of the proceedings we must view their testimony in a light favorable to the applicant. Unless their testimony and exhibits are incapable of belief by this Commission or internally contradictory, we will, for purposes of ruling *at this stage of the proceedings*, accept the testimony and exhibits as reasonable predictions and estimations of what may occur in the future. Testimony and exhibits which would be incapable of belief by this Commission would have to be highly implausible based on this Commission's knowledge and expertise in the field of electric power regulation. For example a prediction or projection today by a qualified expert that nuclear fusion technology would be commercially available within six months at costs competitive with conventional sources of generation would be highly implausible to this Commission. Such testimony would not be sufficient to enable a proponent to meet its burden of proof of a preponderance of the evidence on an issue relevant to that testimony.

B. *What is the Proper Interpretation of the Statutory Requirement that the Proposed Facilities "Meet the Present and Future Demand for Electric Power"?*

[3] RSA 162-F:8 requires this Commission to find that the proposed facilities are required to "meet the present and future demand for electric power". In a shorthand fashion the question posed by the statute has been characterized as the "need for power" issue.

At the outset, this is the first case to come before the SEC and the Commission under the statutory scheme laid down in RSA 162-F proposing a transmission line, unrelated to any particular generating facility located in New Hampshire. There are two aspects of the proposed transmission facilities (either the longer 83 mile line or the shorter 6.7 mile line) which raise novel issues. First, the line(s) as proposed by NEET have as their main purpose providing energy and concomittant cost savings, *not capacity*, from the Hydro-Quebec system.[2] Second, the lines will provide energy and dollar savings not only to New Hampshire but will also provide a substantial portion of such savings, in fact the largest portion of such savings, to utilities and their customers located outside of New Hampshire.

The two words in the statute which bear careful examination are "demand" and "power". To utility and electrical engineers the two terms have meaning in that engineers must plan and operate electric systems to provide energy over periods of time to perform work and provide the capability to supply energy at any instant in time when the system is called upon to deliver. To economists the term "demand" means the amount of a commodity that buyers will buy at each specified price in a given market over a given period of time. *Dictionary of Economics and Business*, Nemmers, p. 120 (1976). "Electric power" is the commodity which may have value to buyers either in the form of energy to perform work or the capability to deliver energy at a given instant in time. The statute in question does not specifically stipulate which view of the two terms is appropriate and we can surmise, as with most legislation which regulates in technical areas and which creates administrative agencies to perform the regulatory function, that we are to interpret the statute in practical terms in light of the requirements and needs of the industry to be regulated and its consumers. *See* 2A Sutherland, Statutes and Statutory Construction § 49.05, City of Manchester v Boston & Maine Railroad (1953) 98 NH 52, 99 PUR NS 181, 94 A2d 552.

We find that the terms in question, "demand" and "electric power", are appropriately viewed in either the engineering sense or the economic sense and that the comprehensive scheme envisioned by RSA 162-F is best served by such an interpretation. Accordingly, we construe the term "electric power" to include both energy (i.e. the ability to do work over a period of time) and capacity (i.e. the capability of providing energy at any given instant in time). We also construe the term "demand" in its economic sense (i.e., the amount of electric energy or capacity that buyers will buy at specified prices during given periods of time) and in its engineering and electric systems planning sense (i.e. the amount of electric energy or capacity that the system will be called upon to deliver or have available in a given period of time). Under this interpretation of the statute, the fact that the proposed facility will deliver energy and related cost savings and not capacity to New Hampshire and New England is immaterial to the issue whether the facility meets the demand for "electric power."

The other threshold issue to be decided in interpreting the statute is whether the proposed facility must meet the "de-

[2]This conclusion is based on Mr. Bigelow's testimony at T. 15-43, and will be discussed more fully *infra*.

ınd for electric power" in New Hamp- :re only, New Hampshire and New gland, or New England only. We re- :t the view that the "demand for elec- : power" must be examined in light of : demand for electric power in New gland only. As will be discussed more ly below, it is not necessary for us to cide whether the statute requires us to ·w the "demand for electric power" in : context of New Hampshire alone or ·w Hampshire and New England, be- ıse of the close interrelationships of :ctric systems located in all New En- ınd states.

In rejecting the view that we must ›k to New England alone, the obvious int is that the present statute is an pression of the public policy of the ıte of New Hampshire to regulate the nstruction and operation of bulk pow- electric supply facilities located in the te. We and the SEC are creatures of : government of the State of New mpshire accountable to its citizens. nsequently, we must concern our- ves with the attendant benefits and sts to the citizens of the state we serve. e delicate balancing process estab- ıed by RSA 162-F:8 clearly implies ıt the SEC and this Commission must ess the benefits (i.e. the ability of a :ticular facility to meet present and ure demands for electric power) to w Hampshire citizens and costs (i.e. ruption of regional development, ad- ·se impacts on system reliability and ›nomics and environmental impacts ısed by a proposed facility) to New mpshire citizens before a certificate y issue. If we were to examine New gland cost and benefits only, conceiv- y we would be confronted by the ıation where all of the costs of a ility would be borne by New Hamp- re's citizens and all of the benefits would be achieved by persons outside the state. Absent any clearly expressed and overriding federal policy or statute requiring such a result, we cannot interpret RSA 162-F to require or permit such a result.

We are, however, presented with a unique situation involving the electric utility systems in New Hampshire. This situation prevents us from isolating any review of a bulk electric power facility to be located in the state from its effects on the rest of New England.

The state's largest generating utility, Public Service Company of New Hampshire (PSNH) is a member of the New England Power Pool (NEPOOL). NEPOOL is a voluntary association of the region's electric utilities which operate in concert under an agreement designed to reduce electric costs and improve system reliability for all its members. Under NEPOOL operating procedures all generating units are centrally dispatched so that the least costly units available are operating at any given time. NEPOOL members share in the savings generated by this economic dispatch system. Maintenance on plants within the system is scheduled so that NEPOOL members will have reliable capacity available from the pool when their units are undergoing maintenance. In the event of unscheduled outages of a member's unit, NEPOOL makes power available to that member so that its customers may be served. In the event of a system-wide emergency, NEPOOL will provide power on essentially a rationed basis so that the burdens of the emergency are shared. NEPOOL also provides reserve margins whereby operating generating units of one member are backed up by the availability of generating units of another member. Bulk power facilities are planned by the NEPOOL Planning Committee and financial resources of members are committed to such units for their construction and operation. The proposed facilities are "Pool Planned" units. (Ex. 3, 9-13) (T. 3-23).

As a result of the integration of the electric utility systems in New Hampshire[3] with other electric utility systems in the region, any increase in the reliability of the NEPOOL system as a whole, any reduction of the risks of curtailed power supplies or system emergencies, and any increase in the availability of less costly energy available to pool members during periods of maintenance will inure to the benefit of New Hampshire. For these reasons, we find it unnecessary to decide whether we view the proposed facility in terms of New Hampshire alone or New Hampshire and New England. Because of the nature of New Hampshire's electric supply systems we, perforce, are conferring benefits on New England when we confer benefits on New Hampshire and vice versa.

C. *Has the Applicant Met Its Burden of Proof on the Need for Power Issue at this Stage in the Proceedings?*

[4] As we have stated, we find that NEET has met its burden of proof *at this stage in the proceeding.* This conclusion is made in the context of the findings of this Commission under subparts A and B, above. NEET's burden at this stage is to establish by a preponderance of the evidence that the proposed facilities are required to meet the present and future demand for electric power. We have interpreted demand to mean that savings will be generated from the proposed facilities to reduce costs of electric power, causing a greater quantity of electric power to be purchased by consumers who are willing to pay the price. By demand we also mean that power will be supplied via the proposed facilities at prices at which purchasers will buy the power and that the proposed facilities will improve the ability of electric systems in New Hampshire and New England to deliver power when it is called for by the consumers of electricity. We have defined "electric power" to mean both energy (the ability to perform work over time) and capacity (the ability to provide energy at any instant at which it is demanded).

The next step is to assess the testimony and exhibits offered by the applicant to determine whether sufficient evidence has been introduced to meet the definitional criteria discussed above. As we also discussed, the evidence at this stage in the proceedings will be assessed in a light favorable to the applicant.

NEET offered two witnesses in support of its case on need for power: Mr. Robert O. Bigelow, President of NEET and Vice President in charge of Planning and Power Supply for New England Power Company; and Roland H. Lalande, Technical Assistant to the Vice President of Production and Transmission, and Consultant in negotiations with interconnected systems for the Power Control Department for Hydro-Quebec. (T1-25; 14-17, 18) Mr. Lalande and Mr. Bigelow offered testimony and exhibits on the availability of power from Hydro-Quebec and Mr. Bigelow offered testimony on the need for power in New Hampshire and New England (Ex. 3-9, 103).

Before we can determine whether there is sufficient evidence in the record

[3] The New Hampshire Electric Co-op is not a member of NEPOOL. However, it shares in the benefits in that its wholesale suppliers of electricity have the NEPOOL opportunity to operate at reduced costs.

enable NEET to meet its burden on ie need for power in New Hampshire id New England, it is first necessary to etermine whether there is sufficient vidence in the record to support a nding that there is any power available hich will flow over the proposed trans- iission line. We are, therefore, required determine whether NEET has met its urden that there is power available om Hydro-Quebec.

All parties concede that the proposed cilities will either directly connect with ansmission systems of Hydro-Quebec he 83 mile line) or indirectly, through ermont, connect with transmission sys- ms of Hydro-Quebec (the 6.7 mile ne). The purpose of these interconnec- ons is to tap into the Hydro-Quebec enerating and transmission system so iat energy may flow back and forth over ie lines between Hydro-Quebec and ew England electric systems. (NEET pplication, pp. 1-2).

Hydro-Quebec is a large electric system wned by the Government of Quebec, anada. (T 14-21,22). Hydro-Quebec is esently interconnected with New York, ntario, Newfoundland-Labrador and ew Brunswick, Canada, and exports pow- to New York, Ontario and New Bruns- ick. (T 14-23) (Ex. 103, p. 5).

The applicant offered testimony rough Mr. Lalande that 95% of the enerating capacity of Hydro-Quebec is om hydroelectric plants and that Hy- o-Quebec has a storage capacity asso- ated with its hydroelectric generation approximately 58,000,000 MWh. (Ex.)3, p. 3) Mr. Lalande also testified that ydro-Quebec had planned a genera- on expansion program and that, while ie generation expansion program was idergoing review (T. 14-46), Hydro- uebec was not considering cancellation three hydro-electric projects and a nuclear project (T. 14-77) (Ex. 44, last page). Total estimated generation capacity for these units according to Exhibit 44, the Hydro-Quebec Annual Report for 1980, is 7,291 MW. At another point in the record Mr. Lalande testified that Hydro-Quebec would adhere through 1986 to the capacity expansion program outlined in his Exhibit 104. (T. 14-57).

Mr. Lalande also testified as to the recent revision by Hydro-Quebec of its load forecast over the period of 1980 - 1998, (Ex. 103, p. 4) (Ex. 105, English translation). According to this testimony and the exhibits, Hydro-Quebec's load growth forecast had been reduced from 6.1% to 4.7%. Mr. Lalande testified that the revised forecasts would make surplus energy available over the next ten years (Ex. 103, pp. 7-8) (T. 14-37). Mr. Lalande also testified to the possibility of negotiating seasonal capacity contracts and firm capacity contracts with New England systems. (T. 14-23, 24) (Ex. 103, p. 8).

With respect to the interest of Quebec in establishing a relationship with NEET and NEPOOL, Mr. Lalande testified that Hydro-Quebec and NEPOOL had virtually completed negotiation of an "energy banking" contract and an "interconnection" agreement and were in negotiations on a "PASNY type" contract. (T. 14-26). Total estimated costs of the portion of the transmission line and related facilities north of the Quebec-New Hampshire border necessary for the interconnection between the two systems, according to Mr. Lalande, are \$209,460,000 U.S. Dollars as of 1986. (Ex. 103, p. 6). Mr. Lalande testified that Hydro-Quebec intended to proceed with the project and to make the necessary expenditures to keep the project on schedule. (Ex. 103, p. 7).

On the basis of this evidence, we find that the applicant has met its burden of proof on the issue as to whether there is energy available to New Hampshire and New England from Hydro-Quebec and a willingness on the part of Hydro-Quebec to enter into agreements with NEPOOL.

We must now examine whether NEET has met its burden on the issue of whether the available power is needed to meet the present and future demand for electric power in New Hampshire. The answer to this latter question turns on several factors. These factors are: the type and quantity of available power, the energy and capacity needs of New Hampshire utilities, the relationships of New Hampshire utilities to the New England Power Pool and the cost savings associated with the available power. NEET's case on this issue turns on the testimony of Mr. Bigelow and related exhibits.

Before reviewing the evidence, it bears remembering that we are addressing the question whether the smaller transmission lines at approximately ±300 KV and 690 MW (either 83 or 6.7 miles) are required to meet the need for power. As we noted earlier the larger sized lines are not before us for the reason that NEET has not filed an application for Phase II of the project. Accordingly, the alternate lines proposed must be examined in light of their smaller size and their attendant capability. Under the circumstances and based on the record before us, we cannot say that NEET has introduced sufficient evidence to justify the smaller-sized lines from the standpoint that they will provide needed capacity in the future. Mr. Bigelow testified repeatedly that construction of the larger sized line was warranted in view of probable needed capacity for New England utilities by the mid to late 1990's. Mr. Bigelow's testimony did not address the value of the smaller sized line in terms of future capacity needs for mid to late 1990's and it appears from the testimony that the smaller sized line was not contemplated for this purpose. (T. 15-43). We also note that Mr. Lalande testified that, at most, seasonal capacity would be available through the early 1990's from Quebec and that there was a possibility of firm capacity being available but only if Hydro-Quebec received certain financial commitments to purchase that capacity from New England utilities. (T.14-66, 67).

We are mindful that it was not until the last day of the hearing on April 23, 1982, that the applicant was informed of the decision to require an application for Phase II or accept a reduced size for the lines. However, we do find that NEET has met its burden on the need for power issue based on the energy exchanges alone.

Mr. Bigelow has testified that there are four primary bases of agreement between NEPOOL and the participants (New England utilities) in the line and Hydro-Quebec. These bases for agreement according to Mr. Bigelow and Mr. Lalande are the "energy banking" arrangement, the sale of energy surpluses, the purchase of entitlements of power by any one of the participants and a "PASNY type" arrangement. (Ex. 3, 45 and 47). Before examining the details of these arrangements as described in the testimony and the record, it is necessary to discuss the participation of particular utilities, especially PSNH, in the arrangements.

According to Mr. Bigelow and Mr. Lalande a committee of NEPOOL is engaged in the negotiations with Hydro-Quebec concerning the interconnection and proposed exchanges of power. NE-

'OOL is negotiating on behalf of its ıembers. NEET has been selected by IEPOOL to construct the facilities (eiher the longer or shorter line and the onverter station) and will be reimıursed by the participating utilities for he costs, operation and maintenance of he line. Depending on the nature of the rrangement and based on certain, precribed formulae set forth in the draft greements, the participant will either hare in cost savings resulting from opration of the line or purchase entitleıents of power at costs which will be ompetitive with costs an entitlement ıurchaser would incur but for the availbility of the line.

According to the draft of the "Energy ßanking Agreement" (Ex. 47) and the estimony of Mr. Bigelow, daily exhanges of energy between NEPOOL nd Hydro-Quebec will occur over the ransmission facility. During periods of ıff-peak loads in New England, New :ngland utilities will operate their relaively efficient, low operating cost generting plants (coal-fired and nuclear tations) and export the energy generatd to Hydro-Quebec. Hydro-Quebec will ıse this energy to serve its domestic oad. The availability of this energy hrough the transmission facility will enble the Hydro-Quebec system to store ater behind its dams during this offeak period. The water stored presumbly would have been converted to nergy to serve Hydro-Quebec's load luring the off-peak period but for the vailability of energy via the transmision facility. The water stored behind the lams will be converted to energy during he peak periods for both systems and an mount of energy equivalent to the mount of energy shipped north by the Jew England utilities will be shipped outh via the transmission facility. The energy shipped south will displace more costly energy which would have been generated by more costly and less efficient generating units which New England utilities would have to operate during the peak hours. From these transactions savings would be generated which would reflect the difference between the incremental cost of producing energy to supply Hydro-Quebec during the off-peak hours and the decremental costs to New England utilities of energy displaced during peak hours when energy is transmitted south from Hydro-Quebec. (See Supplement I, Ex. 47). For the first six years of the agreement, the New England participants would receive 60% of the savings generated and Hydro-Quebec would receive 40% of the savings. After six years the savings would be split 50%-50%. (Ex. 47, Article IX, 9.2).

The energy surplus and entitlement arrangements were explained by Mr. Bigelow's testimony and are found in the "Interconnection Agreement" (Ex. 45). According to this evidence, each participant in the facility has the right to negotiate an entitlement for power from Hydro-Quebec up to the amount of each participant's pro-rata share. As explained by Mr. Bigelow, the pro rata share for each participant is determined by calculating the percentage of each participant's 1980 kilowatt hour load to the total 1980 kilowatt hour load of the New England utilities. An entitlement as described by Mr. Bigelow was any arrangement between a participant and Hydro-Quebec which does not involve energy banking, purchase of energy surpluses, energy or spinning or ready reserve transactions.

According to Mr. Bigelow entitlement transactions take precedence over other transactions utilizing the transmission

facility. Whatever capacity remains in the facility after taking into account the entitlement transactions of the participants is utilized for energy banking and other energy exchanges.[4]

Under the "Interconnection Agreement" and the testimony, if energy surpluses are made available from hydroelectric sources in the Hydro-Quebec system, the cost of that energy will be equal to 80% of the incremental costs associated with generating an equivalent amount of energy by New England systems (Ex. 45, Supplement III,2.). The Interconnection Agreement also provides for exchanges of energy derived from nonrenewable sources, emergency power and supplemental energy made necessary by water or fuel availability, governmental actions or widespread disasters. (Ex. 45, Supplements IV and V). As testified to by Mr. Bigelow, the sales of energy surpluses appear to be the key part of the Interconnection Agreement and will generate savings to participants over the next ten years. According to Mr. Bigelow, the savings accruing to NEPOOL as a result of the availability of energy at 80% of New England's costs will go into the "Quebec Savings Fund" and be distributed according to the participant's pro-rata share with one important exception to be noted below.

The fourth arrangement discussed by Messrs. Bigelow and Lalande is the "PASNY type" contract with Hydro-Quebec. It should be noted that the record does not contain even a draft copy of this contract. As Messrs. Bigelow and Lalande described this contract it is similar to a contract negotiated between the Power Authority of the State of New York (PASNY) and Hydro-Quebec for the sale of energy over an eleven year period from 1986 to 1997. (T. 14-84). Under this proposed contract 33 million MW hours would be delivered from Hydro-Quebec to NEPOOL and its member utilities. Hydro-Quebec would anticipate delivering this energy at the rate of 3 million MW hours per year. (T. 14-84). According to Mr. Lalande the energy to be delivered under the PASNY contract will be offered to NEPOOL and its members first and any surpluses over and above the 3 million MW hours per year would be delivered under the interconnection agreement. (T. 14- 85, 86). Mr. Bigelow testified that the cost of the energy to be delivered under the PASNY type contract would be at 80% of the average fossil fuel cost of generation in the New England system and would add an additional 20% savings over and above energy surpluses delivered under the interconnection agreement. (T. 14-119, 120) (Ex. 113). With respect to whether and when the PASNY type contract would be agreed upon between NEPOOL and Hydro-Quebec, Mr. Bigelow testified that he hoped to complete

[4]We have difficulty with the applicant's case that the entitlement under the Interconnection Agreement meet a need for power in New Hampshire. First,we do not know whether PSNH will exercise its right to the entitlement if the line is built. However, we expect this question will be addressed by PSNH when it appears at subsequent hearings. Second, it is not clear what kind of power will be available from Hydro-Quebec under an entitlement purchase. Mr. Lalande testified that there would be at most seasonal capacity (Spring-Fall) available and that Hydro-Quebec experienced sharp winter peaks. (T. 14-66, 67). If PSNH exercised its rights to an entitlement it appears it would get "firm" energy or "seasonal" capacity from Hydro-Quebec for the period of Spring through Fall. We note the peak for PSNH is the winter. However, we could infer from this evidence that PSNH could use its entitlement to reduce its costs, especially when it schedules maintenance for its plants during its off-peak periods or to reduce its somewhat higher costs when it experiences a moderate peak in the summer. We note also that under the Interconnection Agreement, PSNH could sell a part or all of its entitlement to another participant who had greater need for an entitlement. While PSNH would undoubtedly benefit from such a sale we have difficulty ruling that the bartering of contractual rights is what the legislature intended when it required proposed facilities to meet the demand for power.

negotiations within the next two months. (T. 15-93).

To summarize the proposed arrangements according to the testimony of Messrs. Bigelow and Lalande and the exhibits, essentially there is to be an exchange of energy between the two systems based on energy banking which is not dependent on energy surpluses; the delivery of energy surpluses at 80% of the incremental oil-fired energy costs of the New England systems; entitlements to energy and perhaps seasonal capacity to be negotiated individually by participants in the facility and 33 million MW hours of energy to be delivered under a PASNY type contract for an eleven year period at a price to NEPOOL and its members of 80% of the average cost of NEPOOL fossil fuel generation. Each participant will pay its pro-rata share of support costs for the facility and, with the exception of entitlement purchases, will share in the savings generated by these energy exchanges according to each participant's pro rata share.

Given these arrangements, we find that NEET has introduced sufficient evidence to meet its burden of proof that the arrangements described above will take effect. We must now examine the question whether NEET has met its burden of establishing that the energy purportedly made available will meet a present and future demand for electric power as we have interpreted the statutory language. We have earlier construed the statutory language to refer to the demand for energy as well as capacity. We construed the term demand in its economic sense, i.e. the quantity of a commodity which buyers will buy at given prices over a period of time. We have also held that we must examine the demand for power in the context of needs of New Hampshire but that because of the integrated nature of NEPOOL of which PSNH is a member we must also consider the needs of other member utilities of NEPOOL as well.

Determining whether the proposed arrangements will meet the demand for power in New Hampshire is probably the most difficult part of this case. This Commission would hope and expects that the record on this issue will be fully and completely developed in future hearings.[5] However, at this juncture we have only to decide whether there is sufficient evidence in the record to enable NEET to meet its burden of proof.

Mr. Bigelow testified that in addition to the pro-rata share of the Quebec Savings Fund, the utilities in the state in which the major portion of the transmission line was located would receive an additional 5% bonus share (Ex. 3, p. 31). Originally, the 5% bonus share was to be available to the utilities of the host state only if the utility exercised its entitlement purchases under the Interconnection Agreement. Subsequently, and after cross-examination by members of this Commission, the availability of the bonus share was increased. These recent revisions of the arrangement covering the 5% bonus share, according to Mr. Bigelow, awarded the bonus share to the savings generated by energy banking and energy surpluses.[6] (T. 15-97). Mr. Bigelow also testified that with the 5%

[5]Representatives of PSNH have not testified in this proceeding. However, the SEC and the Commission have requested PSNH testimony and appearances by PSNH witnesses were scheduled after April 23, 1982, but now postponed as a result of the action taken on the PEF Motion on April 23, 1982 (T. 14-167).

[6]As is well known to all the participants in this proceeding an alternate route is being planned through Vermont. It is unclear at this time in which state the line will ultimately be built. However, for present purposes we must assume that a line of approximately ±300 KV will be sited in New Hampshire. We will discuss separately in this opinion the question of whether NEET has met its burden on the shorter 6.7 mile line. The latter line assumes that the largest segment of the line will be located in Vermont.

bonus share went the attendant responsibility to the bonus recipient of picking up an additional 5% of the support payments. During the course of his testimony Mr. Bigelow sponsored a number of exhibits which estimated the savings which would inure to New Hampshire under various scenarios and assumed New Hampshire received the 5% bonus share. (Ex. 38, 107, 111, 112, 113). The most instructive of these exhibits for purposes of this discussion are Exhibits 107-110 and 113 and, in particular, Exhibit 109.

With respect to Exhibit 109, Mr. Bigelow testified that in the first three years of contemplated operation of the 83 mile line in New Hampshire the following dollar savings would accrue to New Hampshire utilities and to New Hampshire ratepayers, given rate of return-revenue requirement regulation of these companies by this Commission and the Federal Energy Regulatory Commission.

Case 1	*Case 2*	*Case 3*
Assuming Surplus of 4.6 million MWH/year	Assuming Surplus of 2 million MWH/year	Energy Banking Only
$35.4 million	$12 million	($1.2 million)

With respect to Exhibit 113, Mr. Bigelow described the scenario for a ±450 KV line sited in New Hampshire and the attendant savings to New Hampshire under a PASNY type contract. This exhibit also assumed that two-thirds of all energy purchased up to 3 million MW hours per year was at the lower cost of 80% of average NEPOOL fossil fuel generation costs. The savings were indicated as follows for the first three years of operation.

Case 1	*Case 2*	*Case 3*
(*supra.*)	(*supra.*)	(*supra.*)
$53 million	$24 million	($3.6 million)

Mr. Bigelow also testified that if Exhibit 113 were adjusted to reflect the less costly smaller sized line of approximately ±300 KV sited in New Hampshire, the savings would be greater under a PASNY type contract. Extrapolating the cost figures for the smaller sized line from Exhibit 109 would yield the following savings for New Hampshire under a PASNY type contract:

Case 1	*Case 2*	*Case 3*
$55.4 million	$26.8 million	($1.2 million)

Mr. Bigelow also testified that after the first three years of operation the Case 3 (energy banking only) scenario would show net savings to New Hampshire and that the savings would increase in years 1993 to 1997. (Ex. 111). In projecting these savings Mr. Bigelow obviously made a number of assumptions. In testifying with respect to these assumptions Mr. Bigelow sponsored Exhibit 38. (T. 14- 128-136). An examination of Exhibit 38 discloses that Mr. Bigelow assumed escalation rates of 11% per year for fossil fuel through 1990 and 9% thereafter and operating and maintenance and construction escalation rates of 9%. Cost of capital for construction of the line was estimated to be 12.4% and Mr. Bigelow used this figure as the discount rate for purposes of his present value calculations of future savings. Under cross-examination Mr. Bigelow explained these assumptions and their internal consistencies and we cannot find at this stage of the proceedings that the assumptions were unreasonable (T. 14-128-136).

Mr. Bigelow also testified in response ı questioning that these savings would ; available to PSNH regardless of the ›nerating capacity, type of generation : primary energy requirements of 3NH for the period, 1986 through)95. (T. 14-158). In this testimony Mr. igelow pointed out that since the esti- ated savings were savings achieved by EPOOL, given the entire generating ıd energy requirements of Pool mem- ›rs and the fact that PSNH would be ıtitled to participate in these savings ıder an energy banking, interconnec- ɔn or PASNY type agreement, PSNH ould obtain these savings regardless of ; generating and energy requirements . the time. (T. 14-158-159).

In projecting the savings, Mr. Bigelow so made assumptions concerning the ıture generating and energy require- ıents of NEPOOL and PSNH. Given the ncertainties of future electric power ıpplies in the region, Mr. Bigelow's ısumptions are open to question. How- ʼer, for present purposes and present urposes only, we accept these assump- ons. If anything, these assumptions ıay be too optimistic concerning the)ility of New England utilities to reduce il dependency and to reduce energy ıd capacity costs. If the plans Mr. igelow uses for his assumptions under- ing the projections of savings fall short f their goals, the savings to the Pool ıd New Hampshire will be even greater ır the reason that there will be a higher ependency on oil-fired generation than lanned. Under these assumptions, Mr. igelow assumed Seabrook I and II and lillstone III would be built by 1987 (all ıree nuclear units of approximately 150 MW of capacity (Ex. 3, p. 13). He so assumed that the New England lectric Systems, the region's second rgest utility would be 10% oil depen- dent by 1986, a decrease from 62% in 1981. (Ex. 115, T. 14-144, 145). Mr. Bigelow testified that oil-fired genera- tion should be 29%, down from 62% in 1981. Mr. Bigelow also estimated that by 1987, assuming a 28% ownership of Seabrook I and II and completion of both units, PSNH would rely on oil-fired generation for 10% of its energy produc- tion. Finally, Mr. Bigelow, as noted earli- er, estimated a need for capacity for Pool members sometime in the late 1990's.

Given these estimates and assump- tions concerning future capacity and en- ergy requirements for Pool members and PSNH we cannot say Mr. Bigelow was unreasonable in his estimates in savings generated by the transmission line and the savings to be achieved by New Hampshire. As we discussed earlier NEET has met its burden at this stage in the proceedings in establishing that sur- plus energy is likely to be available from Hydro-Quebec from 1986 through 1995. As Mr. Bigelow pointed out in connec- tion with Exhibit 5, at a projected load growth of between 4% and 5% for Hydro-Quebec, from approximately 274 million MW hours to 398 million MW hours of surplus energy would be avail- able for export from Hydro-Quebec over the period of 1984-1993. Mr. Lalande confirmed Mr. Bigelow's Exhibit 5 and testimony in this regard and stated that Hydro-Quebec's new load forecast was at 4.7% annually through 1990. (T. 14- 24).

In addition to the evidence on savings to be generated by the transmission line, there is evidence in the record of addi- tional benefits to New Hampshire of the availability of energy from Hydro-Que- bec. As noted above, Mr. Bigelow has estimated that 10% of PSNH's energy will come from oil-fired generation in 1987, assuming completion of Seabrook

I and II. Energy from Hydro-Quebec, according to both Mr. Bigelow and Mr. Lalande, may be used to displace a portion of this energy from oil-fired sources. Even though Mr. Lalande testi- fied that Hydro-Quebec was a winter peaking system and Mr. Bigelow testified that PSNH was also a winter peaking system, Mr. Lalande testified that Hydro- Quebec's winter peaks were sharp peaks in demand and that, in all probability, surplus energy could be exported by Hydro-Quebec during winter periods on the "shoulder" of Hydro-Quebec's peak periods. (T. 14-41).

Mr. Bigelow also testified that by 1990, the region as a whole would de- pend on oil for 29% of its electric energy (Ex. 5). He also testified that a major portion of that 29%, some 50 million barrels per year in 1990, would be im- ported from foreign countries. Addition- al reductions in the projected 29% dependency of New England's utilities on foreign oil would, according to Mr. Bigelow, be achieved through deliveries of surplus energy over the proposed line. In terms of projected benefits to New Hampshire, the reliability of New Hampshire's electric supply would be enhanced because of its interdependen- cy with the electric supply system of New England.

To reiterate, on the basis of the fore- going review of the evidence in the record, this Commission finds *at this point in these proceedings* that NEET has met its burden of proof on the "need for pow- er" issue. NEET has adduced evidence tending to establish that savings to New Hampshire will accrue from operation of the line. In light of our interpretation of the statute that the term "demand" im- plies a quantity of a commodity which buyers will buy at a given price, these savings, which will result in a reduction of the price of electricity over what those prices would otherwise be to New Hampshire ratepayers, will meet a "de- mand" for electric power in New Hamp- shire. In view of the evidence, that some oil-fired energy will be displaced on the PSNH system if energy surpluses are made available from Hydro- Quebec, the facility meets the demand for electric power. This demand is prompted by the perceived need of New England utilities, including PSNH, to displace oil-fired generation, which in the first instance is costly and in the final analysis is less reliable because it originates from unsta- ble sources of supply.

There remains the question as to whether NEET has met its burden with respect to the alternate 6.7 miles of transmission line. The two relevant dif- ferences between the 83 mile line and the 6.7 mile line for purposes of the need for power issue are the lower costs of the 6.7 mile line and the unavailability of the 5% bonus share to New Hamp- shire for siting that portion of the line in New Hampshire. A comparison of Exhib- it 110 to Exhibit 109 illustrates the effects of these differences. In sponsor- ing these exhibits, Mr. Bigelow noted that the support costs of the smaller line (Ex. 110) were $6 million for New Hampshire. New Hampshire's share was 8.2% (less the 5% bonus). Exhibit 110, even with the smaller percentage share, shows savings under Case 1 and Case 2, according to Mr. Bigelow. An adjust- ment of the figures of Exhibit 113 (the display of the various cases under a PASNY type contract with Hydro-Que- bec) yields the following savings for the 6.7 mile line over the period of 1986- 1988:

Case 1	*Case 2*
$35.04 million	$17.3 million

The evidence summarized previously th respect to the 83 mile line and its ›tential for oil displacement and im- oved system reliability, is equally rele- nt to the issue of whether NEET has et its burden with respect to the 6.7 ile line. Since we found that this evi- nce enables NEET to meet its burden th respect to the 83 mile line, it follows at NEET has met its burden with spect to the 6.7 mile line.

While we have found that NEET has et its burden of proof at this stage in e proceedings on the need for power ;ue, we are compelled to make a few ›servations for the guidance of the rties and the assistance of the Com- ission if and when this application mes before the Commission for final sposition under RSA 162 F-8. ıroughout the applicant's case the ap- icant has stressed the benefits to New ıgland of the facility at the risk of ving New Hampshire's benefits short rift. Despite this misplaced emphasis, : find that the evidence to date tends to tablish dollar savings accruing to New ımpshire from the construction of this :ility. We should also note that we have ›t seen finally executed copies of the rious agreements under which these vings are to accrue. There are, more- er, difficulties in translating the vari- ;s load forecasts of Hydro-Quebec into ıantities of energy surplus and in relat- ȝ the availability of these energy sur- uses to the capacity expansion ograms of Hydro-Quebec. We have ;o noted our difficulty in perceiving nefits to New Hampshire from entitle- ment transactions. We also have had difficulty in quantifying the oil-fired en- ergy displacement value to PSNH and New England of the energy surpluses from Hydro-Quebec. In deciding this issue the Commission has also been constrained by Mr. Bigelow's assump- tions about the ability of New England's utilities to back out oil-fired generation. Due to uncertainties in meeting energy needs in the future and planning and scheduling new facilities of any type, these assumptions may be unrealistic and deserve greater attention in future hearings.

SUPPLEMENTAL ORDER

For all of the foregoing reasons, it is hereby ordered that:

1. The New England Electric Trans- mission Company, at this stage of the proceedings, has met its burden of going forward on the "need for power" issue for the approximately ±300 KV line of 83 miles and the approximately ±300 KV line of 6.7 miles;

2. The right of the parties to this proceeding to introduce additional, competent and relevant evidence on the need for power issues shall in no way be foreclosed by this opinion and order; and

3. This matter, along with the requi- site number of copies of this opinion and order, shall be referred to the Bulk Power Supply Site Evaluation Commit- tee for such further proceedings as that Committee and the Public Utilities Com- mittee sitting as a joint board shall deem appropriate.

Re Meetinghouse Brook Estates Water Company

DE 82-182, Order No. 15,716
June 22, 1982

REVOCATION *of the public utility status of a water company owned by the same customers it serves.*

By the COMMISSION:

ORDER

WHEREAS, Meetinghouse Brook Es- tates Water Company, (Meetinghouse) was granted authority to operate as a public utility in a limited area in Pem- broke, N.H. in Docket DE 74-124 and Order No. 11,517 (59 NH PUC 246); and

WHEREAS, the Attorney General of the State of New Hampshire has stated that a membership corporation or an unincorporated association that owns and operates a water system for the provision of water only to themselves, would not be as a public utility as de- fined by RSA362:4; and

WHEREAS, the consumers of Meet- inghouse have certified that they are individually the owners of and the exclu- sive customers of the water system; it is

ORDERED, that the authority granted by Order No. 11,517 is revoked, and that Meetinghouse Brook Estates Water Company shall no longer be con- sidered as a public utility as of the date of this Order.

By Order of the Public Utilities Com- mission of New Hampshire this twenty- second day of June, 1982.

Re Pequod Associates, Inc.

DL 82-183, Order No. 15,719
June 22, 1982

APPROVAL *of a special pricing plan for the sale of cogenerated waste heat.*

Clause and resulting in more stable and comprehensible rates; and

WHEREAS, the Commission provided that the revised rolled-in rate will remain in effect for the balance of the year, as revised in DR 83-143, Order No. 16,527 (68 NH PUC 428), unless a hearing is requested by any party; it is

ORDERED, that no new rate will be stated for the New Hampshire Electric Cooperative, Inc. in this month's FAC order; and it is

FURTHER ORDERED, that 11th Revised Page 19A of Concord Electric Company tariff, NHPUC No. 8 — Electricity, providing for a fuel surcharge of $0.037 per 100 KWH, or $0.038 KWH including the Franchise Tax, for the months of July, August and September, 1983, be, and hereby is, permitted to remain in effect for the month of September, 1983; and it is

FURTHER ORDERED, that 11th Revised Page 19A of Exeter and Hampton Electric Company tariff, NHPUC No. 15 — Electricity, providing for a fuel surcharge of $0.241 per 100 KWH, or $0.244 including the Franchise Tax, for the months of July, August and September, 1983, be, and hereby is, permitted to remain in effect for the month of September, 1983; and it is

FURTHER ORDERED, that 5th Revised Page 57 of Granite State Electric Company tariff, NHPUC No. 10 — Electricity, providing for an oil conservation adjustment of 14.2 cents $0.142 per 100 KWH for the months of July, August and September, 1983, be, and hereby is, permitted to remain in effect for September, 1983; and it is

FURTHER ORDERED, that 6th Revised Page 30 of Granite State Electric Company tariff, NHPUC No. 10 — Electricity, providing for a fuel surcharge for the months of July, August and September, 1983, of $0.80 per 100 KWH be, and hereby is, permitted to remain in effect for September, 1983; and it is

FURTHER ORDERED, that 32nd Revised Page 11B of the Municipal Electric Department of Wolfeboro tariff, NHPUC No. 6 — Electricity, providing for a fuel surcharge of $3.19 per 100 KWH for the month of September, 1983, be, and hereby is, permitted to become effective September 1, 1983; and it is

FURTHER ORDERED, that 84th Revised Page 10-B of Woodsville Water and Light Department tariff, NHPUC No. 3 — Electricity, providing for a fuel surcharge credit of ($1.04) per 100 KWH for the month of September, 1983, be, and hereby is, permitted to become effective September 1, 1983; and it is

FURTHER ORDERED, that 81st Revised Page 18 of Connecticut Valley Electric Company, Inc., tariff, NHPUC No. 4 — Electricity, providing for an energy surcharge credit of ($0.65) per 100 KWH for the month of September, 1983, be, and hereby is, permitted to become effective September 1, 1983; and it is

FURTHER ORDERED, that the above noted rates may be adjusted by a factor of approximately 1% depending upon the utility's classification in the Franchise Tax docket, DR 83-205, Order No. 16,524 (68 NH PUC 461).

By order of the Public Utilities Commission of New Hampshire this first day of September, 1983.

68 NHPUC 531

Re Small Energy Producers and Cogenerators

Intervenors: Public Service Company of New Hampshire, Granite State Hydroelectric Association, Pequod Associates, Inc., Claremont Hydro Associates, Newfound Hydro Electric Company, Franklin Falls Hydroelectric Corporation, Rollingsford Manufacturing Company, Concord Steam Corporation, Chamberlain Otis and Waterloom Falls Hydro Companies, Conservation Law Foundation, New England Alternative Fuels, Inc., Office of Consumer Advocate, and Delta Power Engineering et al.

DE 83-62, Fourth Supplemental Order No. 16,619
September 2, 1983

ORDER *establishing interim long-term rate for small power producers and cogenerators; and terms for the use of the long-term rate.*

Commissions, § 11 — Powers — Establishment of rates — Long term — Interim.

The state commission has authority to establish long-term rates under federal and state statutes and, by implication, this includes the lesser authority to set an interim rate. [1] p. 535.

Constitutional Law, § 20 — Rate setting — Due process — Notice and hearing.

The decision-making process of the commission was not structured so as to deny the tariff filing utility due process of law; rates were based for the most part on data and recommendations submitted by the utility, such data and recommendations were prepared over a 12-week period and any nonutility analysis was accepted by the commission only after the utility had notice of the alternative analysis and had a full opportunity to address itself to that analysis on the record. [2] p. 535.

Cogeneration, § 10 — Operating practices — Purchase obligation.

The revised Limited Electrical Energy Producers Act was not intended to limit the application of the purchase obligation of electric utilities to only those facilities which fall within the definition of a limited electrical energy producer as stated in RSA 362-A:1-a, III; an electric utility must purchase the entire output of a qualifying facility, the definition of which includes facilities with a capacity greater than five megawatts. [3] p. 537.

Cogeneration, § 20 — Operating practices — Levelization of price.

The state commission concluded that the levelized long-term rate established in the subject order was consistent with the definition of avoided costs. [4] p. 538.

Cogeneration, § 5 — Qualifying status — Generally — Small power producer or cogenerator.

If a small power producer or cogenerator clearly falls within the statutory definition set out by RSA 362-A:1-a, construed so as to be consistent with the Public Utility Regulatory Policies Act, then rule making is not necessary for the provisions of the Limited Electrical Energy Producers Act to apply; if a party believes that a particular person does not fall within the definition, the matter can be adjudicated on a case-by-case basis either before the commission under LEEPA or before the Federal Energy Regulatory Commission under PURPA. [5] p. 538.

Rates, § 162 — Factors affecting reasonableness — Public interest — Definition.

The definition of the public interest was established in part by the legislature in State Statutes which require just and reasonable rates and prohibit rate discrimination; if the commission can fulfill the requirements of just and reasonable rates without creating a risk of great harm to the prohibition of rate discrimination it must do so. [6] p. 539.

Cogeneration, § 19 — Long-term contracts — Conservative approach.

The conservative approach to setting a long-term rate does not mean selecting a rate that is artificially low; a conservative rate is one which promises not to be too far above or too far below true avoided costs. [7] p. 540.

Cogeneration, § 25 — Purchase rate — Excess of avoided cost — Risk to ratepayer — Mitigating factors.

Any purchase rate in excess of avoided cost in any year entails a risk to the ratepayers due to the possibility that a producer may not generate power long enough to repay the excess; the commission held that such a risk can be addressed in a number of ways: (1) require producer who accepts the utility's long-term rate to deliver its output over the entire term of the rate in a reasonable, reliable manner; (2) limit the amount of front-end loading; (3) require the producer to repay the utility the excess of payments over costs in the event of the termination of service for any reason; and (4) deny access to the long-term rate to producers if the technology involved or the producer's financial capability appears reasonably likely to fail. [8] p. 543.

APPEARANCES: Catherine E. Shively and Sulloway, Hollis & Soden by Eaton W. Tarbell, Jr., and Margaret Nelson for Public Service Company of New Hampshire; Peter W. Brown and Robert A. Olson for Granite State Hydroelectric Association and Pequod Associates, Inc.; Orr and Reno by Howard M. Moffett for Claremont Hydro Associates *et al*; Nathen Wechsler for Newfound Hydro Electric Company; Robert H. Rowe and Representative Eugene S. Daniell for Franklin Falls Hydroelectric Corporation *et al*; Lawrence Keddy for Rollingsford Manufacturing Company; Roger Bloomfield for Concord Steam Corporation; Robert Greenwood for Chamberlain Otis and Waterloom Falls Hydro Companies; Douglas Foy and J. Cleve Livingston for Conservation Law Foundation; Louis G. Audette for New England Alternative Fuels, Inc.; Michael Holmes for the Consumer Advocate; John Sims for Delta Power Engineering; Larry M. Smukler, Sarah Voll, Ph. D., and George Gantz for the commission staff.

By the COMMISSION:

REPORT

I. *Procedural History*

By Order of Notice dated February 25, 1983 the Public Utilities Commission opened this docket for the purpose of *inter alia* updating and establishing the short term and long term rates to be paid by Public Service Company of New Hampshire (PSNH) to small power producers and cogenerators and the methodologies to be employed in deriving such rates. A procedural hearing was held on March 25, 1983 and a prehearing conference was held on April 20, 1983. Based in part on PSNH's representation at that conference that it would require six weeks to prepare testimony based on the alternative assumptions inherent in the findings of the Commission in Docket No. DE 81-312, the Commission issued Order No. 16,410 (May 4, 1983 [68 NH PUC 327]) which established a deadline of June 10, 1983 for the submission of PSNH prepared testimony; a date which was six weeks from the issuance of the Commission's Report and Sixteenth Supplemental Order No. 16,374 (April 20, 1983 [68 NH PUC 257]) in Docket No. DE 81-312. Subsequent to Order No. 16,410, PSNH filed exceptions on May 18, 1983 and a Motion to Define Scope of Proceedings and Other Procedural Matters on May 25, 1983. The latter Motion included a request that the deadline for the submission of direct testimony be extended. The Commission ruled on the matters raised by PSNH in Report and Supplemental Order No. 16,463 (June 9, 1983 [68 NH PUC 394]). That Order articulated the scope of the proceeding (Report, 68 NH PUC at p. 395) and, after noting that PSNH should have been prepared to move forward on the original deadline, granted an extension based on PSNH's representations of necessity (Report, 68 NH PUC at p. 395). The deadline for the submission of PSNH direct testimony was accordingly extended an additional six weeks to July 22, 1983 and a Procedural Hearing was scheduled for July 28, 1983. PSNH duly filed its direct submission on July 22, 1983.

Subsequent to the issuance of Order No. 16,463, a new set of issues was presented to the Commission. Motions to Intervene were filed by the Conservation Law Foundation (CLF), the Community Action Program (CAP), the Consumer Advocate, Pequod Associates, Inc. (Pequod), New England Alternative Fuels, Inc. (NEAF) and Delta Power Engineering. In addition, Pequod and NEAF, citing what has become known as the "Forster Precedent", See, Re Small Energy Producers and Cogenerators (1980) 65 NH PUC 130, requested that a long term rate be established prior to the conclusion of the proceedings so that they could proceed with the development of their projects. PSNH objected to the CLF Motion to Intervene and the Pequod and NEAF requests for an immediate long term rate. The Commission duly granted all of the above Motions to Intervene in Second Supplemental Order No. 16,566 (August 2, 1983)[1] with the exception of that of CLF, which was subsequently granted in Third Supplemental Order No. 16,593 (August 16, 1983) and the Consumer Advocate and Delta Power Engineering which were granted at the hearing of August 10, 1983 (Tr. at 4-3, 20-3). In addition, after hearing argument during the July 28, 1983 Procedural Hearing, the Commission decided to consider the issue of whether an interim long term rate could be established and, if so, what that long term rate should be. Hearings were scheduled, due dates for testimony were established and exceptions were acknowledged in Second Supplemental Order No. 16,566 (August 2, 1983).

The testimony and exhibits were duly filed in accordance with the schedule and hearings were held on August 10, 1983 and August 12, 1983. At those hearings, testimony was taken

[1] CAP subsequently filed a letter seeking to withdraw as an intervenor. This request was granted at the hearing of August 10, 1983 (Tr. at 5-3).

from Paul C. Porter for Pequod, Louis Gerard Audette and Linda Costello for NEAF, John Sims for Delta Power Engineering, and Richard Valentine Perron and Wyatt W. Brown for PSNH. In addition, at the August 10, 1983 hearing, PSNH filed Public Service Company of New Hampshire's Trial Memorandum on Interim Rates for Small Power Producers (PSNH's Memorandum) and Pequod filed Memorandum of Pequod Associates, Inc. in Support of the Commission Authority to Conduct Long Term Rate Setting for Small Power Producers and Cogenerators (Pequod's Memorandum). The Commission established August 22, 1983 as the due date for replies to the above memoranda and deferred ruling on a request by PSNH that it be allowed to orally argue its Memorandum. On August 22, 1983, PSNH filed Public Service Company of New Hampshire's Reply Memorandum on Interim Rates for Small Power Producers (PSNH's Reply Memorandum).

II. *Preliminary Issues*

A. *Request for Oral Argument*

PSNH requested that it be given the opportunity to orally argue its Memorandum (TR. at 8-3 to 18-3). The Commission allowed all parties to make additional written submissions on the issues raised in PSNH's Memorandum and Pequod's Memorandum and deferred ruling on the request for oral argument. PSNH took advantage of the opportunity to put additional written argument before the Commission when it filed its Reply Memorandum.

The Commission has reviewed the written submissions and it would like to commend both PSNH and Pequod for their ability to present clear and understandable written legal argument. The Commission has before it well written and concise statements of the legal issues which it must resolve. In this context, we do not believe that oral argument will add significantly to the debate. Accordingly, the request for oral argument will be denied.

B. *Commission Authority to Establish an Interim Long Term Rate*

PSNH, in its Memorandum, argued that the Commission does not have the legal authority to establish an interim long term rate. In support of this position, PSNH has presented the following arguments:

1) Neither statutory authority or legal precedent permit the PUC to set an interim long term rate (PSNH Memorandum at 2);
2) The scheduling of the interim proceeding has denied PSNH due process and may substantially prejudice its rights (PSNH Memorandum at 6);
3) The testimony submitted by the other parties does not demonstrate the need for interim relief (PSNH Memorandum at 9);
4) If interim relief is to be established, PSNH's approach is the only approach which may be adopted by the Commission (PSNH Memorandum at 11);
5) The Commission lacks the authority to order PSNH to purchase the entire output of a small power producer or cogenerator with a capacity of 20 MW or less (PSNH Reply Memorandum at 2); and
6) The Commission must engage in a rulemaking to establish the criteria to be applied in determining whether a small power producer or cogenerator "qualifies" for the benefits provided in RSA 362-A (PSNH Reply Memorandum at 7).

We shall address each of the above arguments in turn.

1. *Statutory and Judicial Authority*

[1] PSNH has not contended here that the Commission lacks the authority to set long term rates; rather, its argument is directed at the issue of whether the Commission may set an *interim* long term rate. The Commission concludes that it has the authority to establish a long term rate (*See, e.g.*, RSA 362-A:4, Public Utility Regulatory Policies Act of 1978 (PURPA) § 210) and, by implication, this must include the lesser authority to set an interim rate.[2] However, PSNH's arguments, while directed at the scope of the Commission's jurisdiction, can more properly be viewed as an articulation of PSNH's legitimate concerns about the shape or parameters of the interim rate.[3] As discussed in more detail *infra*, the Commission has given due weight to those concerns by providing *inter alia* that the rate set in this order, if selected by a qualifying facility (QF) may not either go up or down. Rather, if the Commission sets a different rate in subsequent proceedings, the QF will be able to "buy out" of the rate set herein by making payments designed to ensure that PSNH's ratepayers have been made whole. In addition, the rate set is conservative (as defined *infra*), based on PSNH data[4] and, subject to the "buy out" provisions described *infra*, may be modified in any of its terms by this Commission or future Commissions on the basis of a contemporaneous record. Cf., Re Granite State Electric Co. (1981) 121 NH 787, 435 A2d 119 (Commission lacked the authority to establish a short term rate which could not be modified). *See*, RSA 541-A:13 VIII. The Commission finds that these steps adequately address the concerns about an "interim" rate raised by PSNH.

2. *Scheduling*

[2] PSNH contended that the schedule set forth in Second Supplemental Order No. 16,566 (August 2, 1983) was truncated to a point which denied it (the) due process of law. PSNH's concern is proper in that if new issues or data were to be introduced during the interim proceedings, PSNH must be afforded adequate notice and an opportunity to be heard. E.g., Union Fidelity Life Insurance Co. v Whaland (1974) 114 NH 832. However, we do not believe that in this instance the decision making process was structured so as to deny PSNH its entitled due process of law. As set forth *infra*, the interim rates established herein are based on the same principles as would be applied to non-interim rates. In addition, those rates are based for the most part, on data and recommendations submitted by PSNH; data and recommendations which were prepared by PSNH over a twelve week time period. To the extent that we ac-

[2]We recognize PSNH's distinction between our substantive legal authority to set the interim rate and the procedural requirements that apply to all Commission actions. Here, we are discussing the parameters of our substantive authority to set a rate. PSNH's procedural objections are addressed at II.B.2. *infra*.

[3]*E.g.*, will the rate be able to go up or down as a result of future proceedings?

[4]For this reason, the rate does not give special consideration to the needs of any party other than PSNH.

cepted any non-PSNH analysis, we did so only after assuring ourselves that PSNH had notice of the alternative analysis and had a full opportunity to address itself to that analysis on the record.[5] Indeed, if the Commission has any procedural concerns, it must be directed to the rights of the intervenors who did not have twelve weeks to prepare testimony and exhibits, did not have an opportunity for discovery on the PSNH submissions, did not have a week to prepare what was, in essence, rebuttal testimony, only had one half of one day to prepare for hearing after receiving the PSNH submittal of August 9, 1983, and did not have notice of PSNH's intent to file a jurisdictional memorandum and seek oral argument (at the same time) (on) the first day of an evidentiary hearing. We have not articulated these concerns to imply that there was any unfairness toward any party; rather, the Commission believes that its schedule fairly balanced the interests of all parties given the need of the intervenors for a rate and the existence of prefiled PSNH data. Accordingly, the Commission finds that its decision making process has been and is consistent with the requirements of due process.

3. *Need for Relief*

PSNH contended that Pequod's and NEAF's testimony do not demonstrate the need for interim relief. We believe this is a factual determination to be made on the basis of the record before us. The record leads us to conclude that witnesses Porter and Audette both made a compelling presentation of the difficulties they have faced in trying to secure a power marketing arrangement and the effect of alternative Commission actions upon the development of their projects. This is discussed in more detail at III.A. *infra.* The Commission finds that there is a need to immediately establish a long term rate.

4. *PSNH's Approach*

PSNH contended that we must as a matter of law base our findings solely on PSNH's submissions. This is a curious argument, particularly since it was submitted prior to the start of evidentiary hearings and the making of the record. It is also an argument that runs counter to well established principles of law; principles which have been embodied in the recently enacted RSA 541-A:13 VIII.

As a matter of discretion, the Commission has relied heavily on PSNH data and assumptions in setting a long term rate. However, this was based on the weight of the evidence in the factual record;[6] evidence which PSNH could not have predicted with certainty when its Memorandum was filed. Accordingly, the Commission rejects PSNH's contention in this area.

5. *Authority to Order PSNH to Purchase*

PSNH has submitted two arguments here. The first is whether the Commission can order PSNH to purchase the entire output of a QF if it does not fall within the definition of a limited electrical energy producer as defined in RSA 361-A:1-a, III. *See also,* RSA 361-A:3. The second is whether the Commission has the authority to set a levelized rate; an authority we have exercised in this order. We shall address each argument in turn.

A. *Purchase of Entire QF Output*

[3] PSNH's argument is based on the language of the revised Limited Electrical Energy Producers ACT (LEEPA) RSA 362-A. PSNH contends that RSA 362-A:3, which requires electric utilities to purchase the output of certain facilities only applies to Limited Electrical Energy Producers (LEEPs). LEEPs are defined in RSA 362-A:1-a, III. as a QF with a capacity of 5 MW or less. By implication, the exclusion of facilities of over 5 MW from the definition carries over into the benefits provided for LEEPs at RSA 362-A:3. Pequod's Memorandum also goes into the issue of the statutory construction of LEEPA at length.

As argued in the two memoranda, the language of LEEPA may be ambiguous on this issue. However, even if the language of LEEPA merits close scrutiny, we believe that it must be construed in light of both state and federal legislative policies to encourage the development of certain types of alternative, more efficient energy resources. We must presume that the legislature, in enacting the amendments to LEEPA, did not intend to make those amendments inconsistent with federal law; law which would pre-empt such inconsistent state legislation. Federal Energy Regulatory Commission v Mississippi (1982) 456 US 742, 47 PUR4th 1, 72 L Ed 2d 532, 102 S Ct 2126. The federal law is clear on this issue. The regulations of the Federal Energy Regulatory Commission (FERC) promulgated pursuant to PURPA § 210 provide in pertinent part:

> Each electric utility shall purchase . . . any energy and capacity which is made available from a qualifying facility . . . 18 CFR § 292.303(a). *See also,* PSNH Prefiled Testimony, Exh. 3, Attachment 2 at 12235.

Accordingly it is clear that an electric utility must purchase the entire output of a qualifying facility. The question of the definition of qualifying facility is resolved at PURPA § 201 and 18 CFR §§ 292.201 *et seq.* Those definitions include those facilities which fall within the LEEPA definition of small power producers and cogenerators RSA 362-A:1-a; a definition which includes facilities with a capacity greater than 5 MW.

Since the above federal law can operate to pre-empt inconsistent state law, Federal Energy Regulatory Commission v Mississippi, *supra,* we must, where offered a choice, construe state law as being consistent with federal law. Accordingly, we conclude that RSA 362-A:3 in combination with RSA 362-A:1-a does not and was not intended to limit the application of the purchase obligation of electric utilities to only those facilities which fall within the definition of a LEEP. Notwithstanding PSNH's argument to the contrary, we believe that this conclusion is reinforced by the language of RSA 362-A:4 which establishes purchase rate standards applicable to qualifying small power producers and qualifying cogenerators.

[5]For example, as indicated *infra,* we (have) accepted an adjustment for working capital. However, PSNH had full notice that the adjustment was proposed and a full opportunity to cross-examine and present direct testimony on the issue. The record indicates that PSNH took advantage of that opportunity. *See e.g.,* Exh. 10 at 4; Tr. at 60–3 to 68–3; Tr. at 4–91 to 4–100.

[6]We certainly cannot predict whether or not the weight of the evidence will favor PSNH data and assumptions in subsequent phases of this proceeding. That determination must be made on the basis of the contemporary record.

B. *Levelized Rates*

[4] As noted in other portions of this order the Commission is allowing a QF the option of choosing a levelized long term rate. PSNH's argument here must be addressed under the assumption that the Commission has sufficient record support to set such a levelized rate; record support which we believe exists and which will be discussed in more detail *infra*. PSNH, however, is contending that even if we do have adequate record support, we do not have the legal authority to set a levelized long term rate. We do not find PSNH's argument persuasive.

PSNH rests its argument on the assumption that a levelized rate is inconsistent with the definition of "avoided cost".[7] As noted *infra*, the factual record reflects that a levelized present value calculation is not inconsistent with PSNH's avoided cost over the term of the obligation (*E.g.*, Tr. at 4-48 to 4-49). The applicable law in this area also leads us to include that a levelized rate is consistent with avoided cost. In construing the term avoided cost, we must turn to the language of the State statutes and federal regulations pertaining to long term rates. We note that the long term rate language of LEEPA at RSA 362-A:4 is, in pertinent part, nearly identical to the language of the previously promulgated FERC regulation on the subject at 18 CFR § 292.304 (d). This supplies an additional reason to construe the LEEPA language so that it is consistent with the federal regulations. In discussing the meaning of the language at 18 CFR § 292.304(d) the FERC said:

> 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 . . . from approving such an arrangement. 45 *Federal Register* 12224 (February 25, 1980); reproduced at PSNH Direct Testimony of July 22, 1983, Exh. 3, Attachment 2.[8]

We conclude that the levelized long term rate established in this order is consistent with the definition of "avoided cost".

6. *Need for Rulemaking*

[5] PSNH contended that the Commission must engage in a rulemaking to determine the qualifying criteria for small power producers and cogenerators. We believe that a rulemaking may be appropriate at some time to refine and apply statutory definitions. However, the statutory definitions are sufficient absent a rulemaking to go forward with this proceeding. We find that the definitions at RSA 362-A:1-a must be construed so as to be consistent with those set forth at PURPA § 201 and 18 CFR §§ 292.201 *et seq* Federal Energy Regulatory Commission v Mississippi, *supra*. If a small power producer or cogenerator clearly falls within that definition, a rulemaking is not necessary for the provisions of LEEPA to apply. If a party believes that a particular person does not fall within the definition, the matter can be adjudicated on a case-by-case basis either before the Commission under LEEPA or before the FERC under PURPA. Accordingly, we conclude that a rulemaking is not a prerequisite to the provisions of this Order.

III. *Interim Long Term Rate*

A. *Need*

The Commission indicated by Order No. 16,566 establishing the separate consideration of an interim long term rate that it would address the question of whether such a rate were needed. On this point, the Commission finds the testimony of Mr. Porter for Pequod and Ms. Costello for NEAF to be very persuasive. Both parties have attempted negotiations in good faith with PSNH, and both have reached critical points in their developments beyond which they cannot proceed without a firm long term rate. Delay in setting an interim long term rate would continue to create uncertainty for developers seeking long term arrangements and would delay these projects by at least one construction season, if not scuttle them permanently. Establishing a long term rate now will provide an appropriate avoided cost basis for evaluating the economies of the projects; if they are economic they can then proceed without delay.

B. *Sufficiency of Evidence*

[6] PSNH raises the concern that the issues involved in setting a long term rate are so complex that the evidence so far received is an insufficient base for the Commission to establish a long term rate. However, the Commission notes that three parties were able to respond on short notice with testimony on the issue and with recommendations as to what the rate should be. Further, the Commission notes that the rate and rate form established here will only apply until a final order is issued in this docket. For this reason, we started with and adopted PSNH data and analysis unless the record clearly persuaded us that an alternative was justified. This "bias" is appropriate because it was Pequod and NEAF which took on the burden of proof by requesting an interim rate and because it ensures that ratepayers will be adequately protected. However, the Commission has also been mindful of the intent of the legislature in RSA 362-A to promote small power producers and cogenerators when it weighed the thoroughness and exactitude of the evidence.

The definition of the public interest was established in part by the legislature in RSA 362-A as well as in RSA 378:7 and RSA 378:10 which require just and reasonable rates and prohibit rate discrimination. If this Commission can fulfill the requirements of the former without creating a risk of great harm to the latter, it must do so. Given this context, the Commission finds the evidence in the record of DE 83-62 to

[7] Avoided cost has been defined by all parties as being the cost incurred by an electric utility of electric energy or capacity or both which, but for the purchase from the QF, such utility would generate itself or purchase from another source. *See also*, 18 CFR § 292.101 (b)(6).

[8] The FERC language sanctions a levelized long term rate if the rate equals *estimated* avoided costs over the term of the obligation. As discussed in more detail *infra*, the levelized rate in this order will be tied, for some purposes, to actually experienced avoided costs. We believe that this affords additional protection to PSNH's ratepayers.

be sufficient at this point to enable the Commission to act under RSA 362-A by setting a long term rate.

C. *Definition of "Conservative"*

[7] As indicated in RSA 362-A and the language of PURPA, the appropriate basis for setting rates for purchases from small power producers and cogenerators is the utility's avoided cost. See also, American Paper Institute, Inc. v American Electric Power Service Corp. (1983) 461 US 402, 103 S Ct 1921; Re Small Energy Producers and Cogenerators (1980) 65 NH PUC 291, 292, 293. All three witnesses accepted this premise and attempted to establish what the appropriate avoided costs are for PSNH. Witnesses Porter and Audette both appear to recommend a rate at full avoided cost, whereas PSNH, in both their long term contract policy and their proposed "Conservative" long term rate, recommend a rate below full avoided cost. For several reasons set forth below, the Commission rejects a long term rate set below avoided cost and specifically finds that a "conservative" approach to setting a long term rate does not mean selecting a rate that is artifically low.

It is clear that a purchase rate set at avoided cost will entail no change in PSNH's cost of providing service. Thus, customers are unaffected by the change in source of supply, and alternate sources of supply will compete on an equal footing with the sources of supply planned by PSNH. However, if a purchase rate is set below avoided cost, alternate sources of supply will be at a disadvantage compared to the conventional sources planned by PSNH. In this sense, a rate below avoided cost provides a subsidy for conventional sources of supply and discriminates against the alternatives. If a purchase rate is set above avoided cost, the advantage goes to the alternative source of supply and the result is that the company's costs, and hence rates, are increased. Ideally, then, the rate should be at avoided cost. In addition, a conservative rate is a rate which promises to be close to true avoided cost and which avoids creating large errors one way or the other. If a rate errs by being too high, costs will rise; if a rate errs by being too low, alternate sources will be unfairly discouraged and conventional sources, for example foreign oil, will be subsidized.

On the basis of the above, the Commission adopts as a definition of a conservative rate, one which promises not to be too far above or too far below true avoided costs. However, erring on the high side, as it would have a more direct effect on ratepayers, is a more serious concern, and the Commission will weigh the evidence accordingly.[9]

D. *Avoided Costs*

Of the three witnesses testifying on avoided costs, Mr. Porter and Mr. Brown were able to support their recommendations through independent analysis. Mr. Audette used Exhibit 7 as a basis for his recommendation, but was unable to support the numbers contained therein. The Commission will, therefore, focus on the testimony of Mr. Porter and Mr. Brown and will use the same approach in building up an avoided cost estimate.

The estimate of avoided costs begins with the estimate of marginal energy costs. Both Mr. Porter and Mr. Brown used figures produced by the computer model PROSIM as a base. However, in this record we have three sets of numbers for the period 1983 to 2002. These are PSNH's marginal cost numbers, Exhibit 3 Page III-8 Column 2; PSNH's Rigorous Method Numbers, Exhibit 3 Page III-8 Column 3; and Commission requested scenario numbers, Exhibit 4 Column 3. Mr. Brown uses the marginal cost numbers and Mr. Porter uses the Commission scenario numbers, adjusted for the rigorous method, but supplies an independent estimate for 1986. The effect of the above selection is that Mr. Porter used what appears to be the highest numbers over the 20 years and Mr. Brown used the lowest. Mr. Porter's independent analysis for 1986 yielded the interesting result of a lower number than the adjusted Commission scenario numbers (*See*, TR. 116-3), thus providing an independent indication of PROSIM reliability. Accordingly, the Commission agrees with Mr. Brown that PROSIM appears to be quite reliable and is the best basis for estimating avoided energy costs for the purposes of an interim long term rate.

However, Mr. Brown's argument in support of the marginal cost numbers as opposed to the rigorous method numbers is unconvincing. Mr. Brown himself admitted that the rigorous method includes additional avoided costs that are ignored in the marginal cost method (Tr. 4-88). The marginal cost numbers are lower than the rigorous numbers because certain costs are ignored. Therefore, the most conservative approach is to use the rigorous method.

As to the Commission requested scenario, Witness Brown testifies that the differences from PSNH's marginal cost numbers depends on the year and, on average, are not very large. In addition, the Commission notes that the Commission requested scenario was not given using the rigorous method and we therefore do not know what the compound effect would be. Further, at this time in the proceeding, the Commission does not believe it appropriate to address the complex issue of what assumptions regarding growth and/or Seabrook are most appropriate for calculating avoided costs. For these reasons, PSNH's Rigorous Method numbers are accepted as the basis for estimating avoided costs for the purpose of setting an interim long term rate.

Both parties have used the 8.8 percent energy loss factor and the Commission will accept this figure for the purpose of setting an interim long term rate.

Mr. Porter next raises the issues of Working Capital and Inventory Expense and recommends that an adjustment to the avoided energy costs be made to reflect savings in working capital and inventory carrying costs resulting from reduced fuel consumption. Mr. Brown disputes Mr. Porter's calculations (Tr. 4-99 to 4-101). After reviewing the testimony, the Commission finds Mr. Porter's arguments to be more persuasive at this time. In particular, the Commission agrees that adjusting inventories for declining oil consumption would reflect good business practice (Tr. 72-3; See also, Re Granite State Electric Co. [1982] 67 NH PUC 819, Report and Sixth Supplemental Order No. 16,240 [68 NH

[9]The Commission must note that as payments to small power producers are flowed through PSNH's ECRM rate component on a dollar for dollar basis, PSNH faces absolutely no risk to its investors from errors in estimating avoided costs. The Company's concerns for its ratepayers is laudable, but in this case the interests of ratepayers are protected by this Commission in accordance with RSA 363:17-a.

PUC 88]; Re Small Energy Producers and Cogenerators [1980] 65 NH PUC 291, 295) and finds that purchases from small power producers will reduce the normal lag in customer receipts over expenses, thereby reducing working capital needs (Tr. 168-3). The Commission notes that working capital is generally calculated in rate cases by use of a standard formula applied to expense items such as fuel less purchased power.

As there is no dispute regarding the specific numbers put forth by Mr. Porter, the Commission will use 45 days for working capital, 60 days for inventory, and cost of capital as indicated in Exhibit 3 Attachment 10 of 15.1% through 1987 and 12.15% thereafter. The inventory adder is, therefore, 2.5 and 2.0 percent in those periods, respectively, and working capital is 1.9 and 1.5 percent.

The remaining avoided cost items are reflective of the capacity value of small power producers. In this area, the Commission finds analytical flaws in the testimony of both witnesses. The basis for most of the argument here appears to be Exhibit 3 Attachment 10 which purports to show the Marginal Costs of Generating Capacity. Mr. Porter used the first three years, adjusted somehow for a change in Seabrook assumptions, and other data shown in Attachments 11 and 13, to derive a .62 cents per KWH factor for capacity. Mr. Brown used the 20 years of data in Attachment 10, adjusted in various ways along with the data in Attachments 11 and 13, to derive a .25 cents per KWH factor for capacity in 1983, escalating at 6.7% per year thereafter. However, Mr. Brown was unsure about the basis of his own analysis in several instances and his adjustments are apparently incorrect in several others (Tr. 4-111 to 4-120). In all instances, Mr. Brown has apparently erred on the side of lowered capacity values (Tr. 4-115, Tr. 4-116).

On the basis of the above, the Commission rejects both witnesses numbers and will use .5 cents per KWH, the existing capacity value assigned to small power production by this Commission in Re Small Energy Producers and Cogenerators, 65 NH PUC 291, 297, 298 as the 1983 base capacity value. As indicated above, no party met its burden of justifying a deviation from the existing rate; a rate that falls in between the high and low figures offered by the parties. As Exhibit 3 Attachments 10 and 13 show, the capacity value over 20 years can be expected to grow, particularly after Seabrook capacity is fully absorbed into the system. This capacity value will, therefore, be escalated at 6.7 percent per year as per the Company's method in Attachment 13.

These additions, adjustments and corrections yield the following estimated avoided costs for the period 1983–2002; and are accepted by this Commission for the purpose of setting interim long term rates:

YEAR	*¢/KWH*
1983	5.668
1984	7.133
1985	6.442
1986	6.332
1987	7.009
1988	6.501
1989	6.920
1990	7.532
1991	8.362
1992	9.522
1993	10.955
1994	11.831
1995	14.354
1996	15.711
1997	17.501
1998	18.642
1999	20.307
2000	21.133
2001	23.306
2002	26.510

E. *Contract Forms*

Through the testimony of Mr. Perron, it is clear that PSNH accepts, in principle, a net present value analysis (Tr. 4–39 to 4–40) to determine if the company's avoided costs are greater than or equal to the payments made to small power producers under long term contracts. Mr. Porter similarly adopts such a method (Tr. 122–3 to 123 –3), as does Mr. Brown in the calculation of marginal capacity costs (Exhibit 3 Attachments 10 and 11). The Commission understands this method to imply that over a specific time frame, the Company and its customers will be neutral between two options with equal net present value, *e.g.*, if the payments to a producer are the same as the avoided costs in net present value. This approach is important as it provides a method of fairly evaluating different time frames and different payment streams while adhering to the same avoided costs. The Commission adopts the net present value comparison for the purpose of setting an interim long term rate, and notes that it provides the simplicity and flexibility required in this case.

[8] However, the Commission is sensitive to the concerns of the Company that any purchase rate in excess of avoided cost in any year entails a risk to the ratepayers (*cf*, Exhibit 3 Page III–17) due to the possibility that a producer may not generate long enough to "repay" the excess. The Commission believes this risk can be addressed in a number of ways. First, a producer who accepts a PSNH long term rate is obliged to deliver his output to PSNH over the entire term of the rate in a reasonably reliable manner. Second, a limit on the amount of "front-end loading" is appropriate to limit the risk exposure of ratepayers. The Commission notes that the risk we are referring to here is small in dollar terms compared with, for example, the risk of a major generator outage. Third, the Commission can and will require a producer to repay to PSNH the excess of payments over costs in the event of the termination of service for any reason. Finally, access to the long term rate can be denied to producers if the technology involved or the producer's financial capability appears reasonably likely to fail. The Commission notes that in most cases, judgment as to the liklihood of failure can be deferred to a project's debt and equity investors; credible investors are not likely to invest in a project with a high probability of failure. For the time being, the Commission will embody the first and the third items in the terms applicable to the long term rates. In addition, the Commission will set a maximum first year price of 9¢ per KWH, equal to PSNH's new contract offering, to limit ratepayer exposure and will provide an opportunity for PSNH to challenge any long term rate applicant on feasibility grounds.

For the purpose of calculating net present value, the small power producer's output is assumed equal in all years and the purchase rates and avoided costs are compared by calculating cumulative net present value using the PSNH discount rates of 15.1% through 1987 and 12.15% thereafter. If the producer's start-up date is after July 1, the first year of the contract for purpose of these calculations will be the calendar year following.

F. *Terms of a Long Term Rate*

One of the issues that has not received great attention as yet in these proceedings is the nature of a long term rate with respect to the obligations of all parties. This Commission wishes to indicate that this issue will be addressed more fully as this docket proceeds. However, certain ground rules must be established prior to the final formulation of a long term rate.

First, the Commission will continue to apply its prior rulings regarding *inter alia* interconnections, metering and capacity audits, See e.g., Re Small Power Producers and Cogenerators (1981) 66 NH PUC 83.

Second, the Commission believes that a long term rate under PURPA and RSA 362–A is in the nature of a legally enforceable obligation. In essence, it is similar to the agreement between the utility and its retail customers embodied in the filed tariffs of the utility with this Commission. However, a long term rate applies to a considerably longer term than tariffed rates and the Commission must, therefore, establish a procedure that makes clear the precise relationship of the parties. For the time being, the Commission will require the following:

Any small power producer wishing to invoke the long term rate established by this Order must file with this Commission and the Company, a certificate signed by the duly authorized agent of the entity, attesting to the following:

1. that, unless the producer elects the termination option set forth at paragraph 5 below, the producer will sell its entire output to PSNH at the specified rates over the entire applicable time period;

2. that the producer will abide by all applicable rules, regulations and orders of this Commission and will obey the Commission's directives in the case of any disputes with PSNH;

3. that the producer will make all reasonable efforts to provide reliable service to PSNH over the life of the obligation;

4. that, in the event that the producer opts for a rate above avoided costs in any year, the producer agrees to pay PSNH the net of excess payments over avoided costs, in net present value, actually experienced, in the event of a service termination prior to the end of the obligation period;[10]

5. that service may be terminated on 60 day's notice at the option of the producer;

6. that the producer agrees to appear before this Commission with such documents as may be requested upon reasonable notice, to the extent required by this Commission to fulfill its statutory obligations; and

7. that in all respects not otherwise provided herein or in Commission orders, the producer will adhere to the non-pricing terms in the PSNH standard long term contract referred to at Tr. 4–14.

[10]The Commission notes that the net present value payment will be based upon the PSNH discount rate of 15.1% through 1987 and 12.15% thereafter which was put on the record in this proceeding. The Commission recognizes that in its proposed revision to its long term contract policy, PSNH is proposing that 8% interest be accrued for some purposes in a "payback pool" (Tr. 4-16). We will not comment on the applicability of an 8% rate for the purpose of a voluntarily negotiated contract. However, for the purpose of a Commission established rate, we believe that the 8% rate is not sufficient to protect the PSNH ratepayers. PSNH's cost of capital as reflected in its discount rate is the appropriate figure because it will ensure that PSNH's ratepayers are left "whole" in the event of a "buy out".

G. *Applicable Rates*

Given the foregoing, the precise specification of an interim long term rate is achieved by identifying the appropriate time period and the cumulative net present value of avoided costs. All values below are expressed in mid-year 1983 dollars, and all avoided cost values are assumed to be mid-year nominal dollars. In order to specify 20 year contract values beginning after 1983, the avoided cost values were escalated beyond 2002 at the average annual growth rate for the 20 year period. Any stream of contract payments over the specified years that starts below 9¢/KWH and that is less than or equal to the following values in cumulative net present value is an acceptable long term rate.[11]

Initial Contract Year	*20-Year Contract Rate*	*15-Year Contract Rate*	*10-Year Contract Rate*
1983	70.221	56.206	40.423
1984	67.155	53.547	37.892
1985	63.460	50.272	34.716
1986	61.003	48.121	33.121

A ten year rate appears to be the shortest period any developer would reasonably need to cover debt service. A 20 year rate appears to be the longest period any developer would require, and also is the longest period for which data exists.

Commission analysis of these rates indicates that neither NEAF's nor Pequod's proposals, as is, satisfy these requirements. However, the Commission believes they are reasonably close enough to those proposals to allow NEAF and Pequod to go forward and make a final feasibility determination.

For a given producer obligated under a specific period and rate, the actual avoided cost and contract payments will be reported as part of PSNH's ECRM proceeding, and a present worth of excess payments over avoided costs (as determined in accordance with the Commission's final order in this proceeding) will be calculated and tracked.

E. *Miscellaneous*

The Commission does not, by its decision here, preclude any developer and PSNH from voluntarily negotiating a contract which contains terms inconsistent with this Order. All terms in this Order, including but not limited to the pricing and "buy out" provisions will be subordinate to the terms of a voluntarily negotiated power marketing contract. The Commission further notes that the interim long term rate, as established, is not subject to change. However, should circumstances later change, a small power producer may

[11]The values are expressed in cents per KWH and equal the sum of the 1983 present worth avoided costs in each year for the appropriate period. E.g., the 20 year rate which commences in 1983 may be represented as:

$\sum_{n=1}^{20} = 70.221$¢/KWH. To continue the example any 20 year 1983 rate may be selected by a QF so long as it falls within the guidelines set forth in this Order and its present value sum does not exceed 70.221¢/KWH.

"buy out" his contract on 60 day's notice by paying PSNH the net present value of the excess of contract payments over avoided costs, in which case the ratepayer is fully compensated. Again, the risk of default or overestimation of avoided cost is a risk entirely borne by ratepayers; no risk accrues to PSNH's investors. The risk of underestimation of avoided cost is the risk to society that small power production will be unnecessarily discouraged.

VI. *Further Proceedings*

As noted above, the rate set herein is an interim rate which may be revised in any manner on the basis of the record as it develops. It is our intention to continue with this proceeding and to set a schedule that will allow the full development of a record. The parties have thus far been unable to agree on a procedural schedule. In the absence of agreement, the Commission will establish the following schedule for the continuation of proceedings in this docket:

September 20, 1983:	Conference of Parties on PROSIM computer model.
September 30, 1983:	Staff and Intervenor initial data requests due.
October 30, 1983:	PSNH responses due.
November 30, 1983:	Staff and Intervenor follow up data requests, including requests for PROSIM runs due.
January 16, 1984:	PSNH responses due.
February 6, 1984:	Staff and Intervenor direct testimony and exhibits due. PSNH supplementary testimony due.
February 20, 1984:	Data requests due from all parties.
March 12, 1984:	Responses due.
March 27, 28 and 29, 1984:	Hearings
One week after hearings:	Prefiled rebuttal testimony due from all parties.

Additional proceedings will be scheduled at the call of the Commission. We note our willingness to vary from the above schedule so long as all parties and the Staff agree to an alternative schedule.

V. *Conclusion*

In issuing this interim Order we are mindful of both state and federal policy which supports the development of efficient and alternative energy resources to the extent that they can economically compete with conventional sources. LEEPA; PURPA; American Paper Institute, Inc. v American Electric Power Service Corp., *supra*; Federal Energy Regulatory Commission v Mississippi, *supra*. We are also mindful of our obligation to protect ratepayers from the effect of a nonconservative rate as defined herein. RSA 363:17–a. We believe that this Order represents a careful balancing of all interests on the basis of the record before us. We shall be monitoring the effects of this Order as the proceeding progresses. We will also need and welcome the input of all parties.

Our Order will issue accordingly.

SUPPLEMENTAL ORDER

Upon consideration of the foregoing Report, which is made a part hereof; it is

ORDERED, that an interim long term rate is established as provided in the foregoing Report; and it is

FURTHER ORDERED, that all limited electrical energy producers, small power producers or cogenerators who wish to receive the aforementioned interim long term rate must adhere to the terms provided in the foregoing Report; and it is

FURTHER ORDERED, that the procedural schedule for the remainder of the proceedings in this docket shall be set forth in the foregoing Report.

By order of the Public Utilities Commission of New Hampshire this second day of September, 1983.

Re Lifeline Rates

DP 80-260, 21st Supplemental Order No. 16,620
September 2, 1983

ORDER *affirming commission policy on compensation for attorney's fees.*

Costs — Attorney's fees — For intervenors — Compensation.

The commission affirmed its position that intervenors may be compensated only for those attorney's fees related to the actual preparation and advocacy of a rate case and not for those attorney's fees related to efforts to recover such compensation. [1] p. 548.

Costs — Attorney's fees — Calculations — In-house counsel rate.

When awarding attorneys' fees, the going rate for in-house counsel with similar experience should be used as a guideline rather than the prevailing market rate for private attorneys. [2] p. 549.

Costs — Attorney's fees — Allocation — Methodology.

The commission said it would continue to allocate the responsibility for an award of attorney's fees by dividing it among the utilities involved in a case on the basis of their respective gross revenues. [3] p. 549.

APPEARANCES: as previously noted.

By the COMMISSION:

REPORT

In Report and Eleventh Supplemental Order No. 15,642 (May 11, 1982 [67 NH PUC 318]), the Commission found VOICE eligible for compensation in this docket. In Report and Fourteenth Supplemental Order No. 15,857 (August 21, 1982 [67 NH PUC 610]) VOICE was awarded compensation for "Phase I" of the proceedings in the instant docket. "Phase I" of the docket ended with the issuance of Order No. 14,872 (April 30, 1983 [66 NH PUC 166]). Subsequent to that date the Commission instituted "Phase 2" of the docket which ended with Nineteenth

69 NH PUC 352

Re Small Energy Producers and Cogenerators

Intervenors: Public Service Company of New Hampshire, Granite State Hydroelectric Association, Franconia Power and Light Associates, Inc., Claremont Hydro Associates, Newfound Hydro Electric Company, Franklin Falls Hydro Electric Company, Rollingsford Manufacturing Company, Concord Steam Corporation, Waterloom Falls Hydro Companies, Conservation Law Foundation of New England, Inc., New England Alternative Fuels, Inc., Office of Consumer Advocate, and Delta Power Engineering et al.

DE 83-62, Eighth Supplemental Order No. 17,104
61 PUR4th 132
July 5, 1984

ORDER *establishing rates for small energy producers and cogenerators.*

Cogeneration, § 36 — Rate design factors — Time-differentiated pricing.
To qualify for time-of-day rates, small power producers must have a time-of-day meter or they will receive either the off-peak rate for all energy sold or an average "all hours" rate. [1] p. 356.

Cogeneration, § 28 — Avoided costs — Energy and production costs.
The energy component of avoided cost rates was calculated by multiplying marginal energy cost by loss factor by indirect factor. [2] p. 357.

Cogeneration, § 28 — Avoided costs — Energy and production costs.
Marginal energy cost is a cost, composed primarily of fuel, that will be avoided if a kilowatt-hour of energy is produced by a small power producer. [3] p. 357.

Cogeneration, § 37 — Rate design factors — Line losses.
The loss factor is intended to adjust for energy losses which occur in the generation and transmission of electricity. [4] p. 357.

Cogeneration, § 28 — Avoided costs — Energy and production costs — Indirect factor.
The indirect factor used in computing the energy component of avoided cost rates represents the combined effects of adjustments to methodology, inventory costs, working capital costs, and operating and maintenance costs. [5] p. 358.

Cogeneration, § 28 — Avoided costs — Energy and production costs.
The amount paid to small power producers for the energy component will be calculated by multiplying the energy component by the energy produced during the time period for which payment is made. [6] p. 358.

Cogeneration, § 27 — Avoided costs — Capacity costs — Calculation.
The capacity component is calculated by multiplying the marginal cost of capacity per kilowatt per year by the loss adjustment factor. [7] p. 358.

Cogeneration, § 27 — Avoided costs — Capacity costs.
The marginal cost of capacity per kilowatt is an annual cost based on estimated avoided costs of generation and transmission capacity. [8] p. 358.

Cogeneration, § 30 — Rates — Calculation.
The amount to be paid a small power producer is calculated by multiplying the capacity component by the audit value of the site by the peak reduction factor. [9] p. 359.

Cogeneration, § 30 — Rates — Calculation — Audit value.
The audit value of a small power production site is determined by the commission on the basis of historical data and the characteristics of the specific plant. [10] p. 359.

Cogeneration, § 25 — Avoided costs — Peak-load reduction.
The peak reduction factor relates the amount of actual peak-load reduction of a small power producer to its audit value. [11] p. 359.

Cogeneration, § 24 — Rates — Bridge rates.
The commission rejected a proposal for a short-term bridge rate for eligible small power producers that included ratepayer subsidies, stating that rates based on subsidies should be adopted only where the evidence conclusively demonstrates that such rates are necessary and in the public interest. [12] p. 367.

APPEARANCES: Catherine E. Shively, Esquire and Sulloway, Hollis & Soden by Eaton W. Tarbell, Jr., Esquire and Margaret Nelson, Esquire for Public Service Company of New Hampshire (PSNH); Robert A. Olson, Esquire for Granite State Hydroelectric Association and Franconia Power & Light Associates, Inc.; Orr and Reno by Howard M. Moffett, Esquire for Claremont Hydro Associates, *et al*; Nathan Wechsler for Newfound Hydro Electric Company; Robert H. Rowe, Esquire and Representative Eugene S. Daniell for Franklin Falls Hydro Electric Company *et al*; Lawrence Keddy for Rollingsford Manufacturing Company; Roger Bloomfield for Concord Steam Corporation; Robert Greenwood for Chamberlain Otis and Waterloom Falls Hydro Companies; J. Cleve Livingston, Esquire for Conservation Law Foundation; Goldstein, Manello & Burak by Michael Burak, Esquire for New England Alternative Fuels, Inc.; Michael Holmes, Esquire for Consumer Advocate; John Sims for Delta Power Engineering; Larry M. Smukler, Esquire, Sarah Voll, Ph. D. and Melinda Rafter for the Commission Staff.

By the COMMISSION:

REPORT

I. *PROCEDURAL HISTORY*

By Order of Notice dated February 25, 1983 the Public Utilities Commission ("Commission") opened this docket for the purpose of *inter alia* updating and establishing the short term and long term rates to be paid by Public Service Company of New Hampshire ("PSNH" or "Company") to small power producers and cogenerators ("SPPs"), and the methodologies to be employed in deriving such rates. A procedural hearing was held on March 25, 1983. PSNH filed its direct testimony and exhibits on July 22, 1983. At a hearing on July 28, 1983, the Commission ruled that it would hold hearings to determine if a conservative long-term rate should be set on an interim basis. Following interim hearings, the Commission issued its Report and Fourth Supplemental Order No. 16,619 ([1983] 68 NH PUC 531), establishing a methodology for the calculation of an interim long-term rate based, for the most part, on PSNH data and assumptions supplied in its original testimony. The Commission subsequently issued Report and Fifth Supplemental Order No. 16,664 ([1983] 68 NH PUC 575) which clarified certain aspects of its original Interim Order along with certain terms and conditions for implementing the rate.[1]

The Commission's stated goal in the Interim Order was to arrive at a "conservative" interim long-term rate based on and not exceeding PSNH's avoided costs,

[1]Report and Fourth Supplemental Order No. 16,619 and Report and Fifth Supplemental Order No. 16,664 will be collectively referred to in this Report as the Interim Order.

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as mandated by the New Hampshire Limited Electrical Energy Producers Act, RSA Chapter 362-A as amended ("LEEPA") and the Federal Public Utility Regulatory Policies Act, 16 U.S.C. § 824a-3 *et seq.* ("PURPA"). The Commission started with PSNH's marginal energy costs as developed in the Company's Production Simulation Model ("PROSIM") and then allowed "adders" to reflect the avoided cost of working capital and inventory. It permitted the long-term rate to be front-end-loaded and levelized, but provided for a maximum first year price beginning in 1983 of 9¢ per KWH to limit ratepayer exposure. The Commission also permitted a SPP to "buy out" of its long-term rate by repaying to PSNH the sums advanced under the front-end-loaded portion of the rate. SPPs signing on for the interim long-term rate were required to enter into an Interconnection Agreement with PSNH. The Commission stated that prior orders relating to *inter alia* capacity audits and interconnection would continue to apply. It advised the parties that it wished to explore other aspects of the long-term marketing relationship in further proceedings and set a schedule for the remainder of the docket, a schedule which called for final hearings in March, 1984.

In January, 1984, PSNH requested that the Commission extend the procedural schedule to permit the parties to undertake settlement discussions. The Commission did so in Report and Seventh Supplemental Order No. 16,863 ([1984] 69 NH PUC 29). After notice to all parties who had appeared in the docket, a series of settlement conferences were held at the Commission's offices beginning in February, 1984. Stipulated Recommendations (Exhibit 12) were presented by the parties at a hearing on June 14, 1984, on which all signatories agreed with the exception that Commission Staff, PSNH and the Conservation Law Foundation did not recommend the adoption of Section II.E. (Short-Term Bridge Rate). Signatories to the stipulated recommendations were PSNH, the NHPUC Staff, the Conservation Law Foundation ("CLF"), the Granite State Hydropower Association, Franconia Power and Light and Franklin Falls Hydro Electric Company. New England Alternate Fuels was unable to be present to sign the recommendations, but informed the Commission that it supported the Stipulated Recommendations. Claremont Associates *et al.* did not sign because of a dispute with PSNH not directly involving the terms of the Stipulated Recommendations; however, counsel stated that the dispute did not affect its support for the terms of the stipulations. A number of the original parties did not participate directly in the negotiations. However, many were represented through the Granite State Hydropower Association and none expressed disagreement with the recommendations.

After a complete review of the testimony and evidence, the Commission finds that the record supports the Stipulated Recommendations and that the recommended short and long term rates, terms and conditions provide encouragement for the development of economically efficient small power production while being just and reasonable to the ratepayers of PSNH and in the public interest. We therefore adopt the terms of the Stipulated Recommendations, with the exception of the Short-Term Bridge Rate (Section II.E.) which we will address separately. To the extent to which we do not address any particular stipulated recommendation in this Order, such stipulated recommendation should be deemed to be approved by this Order. All provisions of the Interim Order will continue in effect for those facilities who have elected to take that rate prior to the effective date of this Order. In addition, all prior Commission Orders relating to SPPs, including the Interim Order, will remain in effect to the extent that they are not inconsistent with this Order and shall be superceded to the extent that they are inconsistent with this Order.

II. *COMMISSION ANALYSIS*

A. *Jurisdiction of the Commission*

The Commission's authority to set rates for power sold by SPPs to PSNH is based on both LEEPA and PURPA.

LEEPA was enacted in 1978 "to provide for small scale and diversified sources of supplemental electric power to lessen the state's dependence upon other sources which may, from time to time, be uncertain". RSA 362-A:1. LEEPA requires a public utility serving a franchise area to purchase all electric power offered by limited electrical energy producers in its franchise area, RSA 362-A:3, at rates set from time to time by the Commission, RSA 362-A:4. The Commission's authority to set long-term as well as short-term rates was addressed by the 1983 Legislature, which amended RSA 362-A:4 to provide:

> Public utilities purchasing electrical energy in accordance with the provisions of this chapter shall pay rates per kilowatt-hour to be set from time to time by the Commission. Such rates shall be based on the purchasing utility's avoided costs. The Commission may set long-term rates which shall, at the option of the qualifying small power producer or qualifying cogenerator, be based on the purchasing utility's avoided costs either calculated for the time of delivery or calculated for a specified term at the time the qualifying small power producer or qualifying cogenerator agrees to be obligated to deliver for the specified term. Nothing in this section shall limit the authority of any electric utility or any qualifying small power producer or qualifying cogenerator to agree to a rate for any purchase which differs from the rate or terms or conditions which would otherwise be required by the Commission.

This Order, under RSA 362-A:4 (Supp. 1983), requires certain rates, terms and conditions for those qualifying SPPs who elect to avail themselves of the short or long-term rates, terms and conditions approved herein. Nothing in this Order will prevent any person from negotiating and entering into a contract for the purchase and sale of electric energy at rates and on terms and conditions other than those or in addition to those contained herein.

The Federal Act, PURPA, also passed in 1978, affords the Commission a second independent statutory basis for setting rates for SPPs. PURPA requires electric utilities to offer to purchase electric energy from qualifying small power producers and cogenerators under rules established by the Federal Energy Regulatory Commission ("FERC") and at rates set by state regulatory agencies. 16 U.S.C. § 824a-3. Sub-section (b) of § 824a-3 provides in part:

> . . . 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 small power producers.

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

This order fulfills the Commission's responsibility under PURPA to set just and reasonable rates for sales of electric power to public utilities, based on the utility's incremental cost of alternative electric energy and capacity.

B. *General Provisions Which Apply to Both Short- and Long-Term Rates*

B.1. *Marginal Cost Methodology*

The terms "incremental cost," "avoided cost" and "marginal cost" are used interchangeably for purposes of this Order. The methodology on which this Order is based involves the calculation of marginal energy and capacity costs avoided by PSNH, using principles adopted by the Commission in PSNH's last retail rate proceeding, Re Public Service Co. of New Hampshire (1984) 69 NH PUC 67, 57 PUR4th 563.[2] The methodology is described in more technical detail in the Stipulated Recommendations, Exhibit 12, Attachment 1 ("PSNH System Planning Response Methodology"). Avoided costs are the appropriate basis for SPP rates, from both an economic and legal perspective. It is anticipated that refinements to the marginal cost methodology adopted will be forthcoming and of value to both SPP and retail ratemaking. The Commission recognizes that some aspects of the methodology apply only to retail ratemaking and others need modification for specific SPP application.

B.2. *Rate Structure*

[1] Both short and long-term rates will contain an energy component, expressed in cents per kilowatt-hour (¢/KWH), and a capacity component, expressed in dollars per kilowatt-year ($/KW). Rates will be rounded to the nearest one hundredth of a cent. Time-of-Day rates for the energy component will be available on an optional basis except that time of day metering will be required for SPP facilities with an audited capacity in excess of 1000 KW and for all SPPs who do not sell all of their output to PSNH (*i.e.*, net billing or sale of excess energy). However, as alternatives, SPPs not selling all of their output to PSNH may: 1) use a less expensive non-Time-of-Day meter and receive the off-peak rate for all energy sold to PSNH; or 2) enter into commitments designating amounts to be sold to PSNH which warrant payment of the average "all hours" rate. The Time-of-Day meter will be a solid state meter with battery carryover and other criteria as specified by PSNH. (The current approximate cost of the meter is $650.) All SPPs, including those on Time-of-Day rates, shall continue to pay for the entire cost of metering.

For purposes of the Time-of-Day rates established in this Order, the on-peak hours are between 7 a.m. and 10 p.m., Monday through Friday, excluding holidays. The off-peak hours are between 10 p.m. and 7 a.m., Monday through Friday, and the entire day on Saturdays, Sundays, and holidays. Holidays are defined in Section 12 of the Company's Tariff.

The Commission recognizes that the timing of the implementation of the Time-of-Day option may be subject to meter and manpower availability and the development of administrative procedures by PSNH.

B.3. *Energy Component of the Rate*

[2] The energy component will be calculated as follows: (Marginal Energy Cost) × (Loss Factor) × (Indirect Factor).

[3] *"Marginal Energy Cost"* is defined as the energy-related costs to generate the most expensive kilowatt-hour of energy required by PSNH customers at each hour in a given year, averaged over the appropriate time period. This is also the cost, composed primarily of fuel, that will be avoided if that final kilowatt-hour of energy is instead provided by SPPs. Marginal Energy Cost for the projected period will be provided from PSNH's PROSIM model. The model utilizes the "highest cost block on line" definition, as in Re Public Service Co. of New Hampshire, *supra*, and an arithmetic average of data in each of the time periods.

[4] The *"Loss Factor"* is intended to adjust for energy losses which occur in the generation and transmission of electricity. SPPs can either add losses to portions of the system, or decrease losses, or have no effect at all. If the SPP is large enough, it may by increasing electrical loading increase the losses on a portion of the system, or it may reduce the electrical loadings and the associated losses by providing a source of power closer to the load. For purposes of these rates, the Commission assumes that the typical SPP has a delivery point at the primary voltage system and reduces losses for the portion of the electrical system upstream of the point of the primary voltage interconnection.

The marginal loss factor associated with energy is the average of the marginal values for all hours of the time period. Since losses are a function of load level, the energy related loss factor is slightly different for the first and second halves of the year: 1.092 from January to June and 1.086 from July to December. The value also varies for peak and off-peak periods. The appropriate value for the energy related loss factor on an annual basis for "all hours" is found to be 1.088.

These loss factor values were determined as part of the comprehensive loss study which PSNH performed for the system planning response method marginal cost study in Re Public Service Co. of New Hampshire, *supra*, and are applicable for both the short and long-term analysis. *See*, Exh. 12, Attachment 2. The values assume that the delivery point is at primary voltage, *i.e.*, the SPP is either directly connected and metered at the primary voltage level or secondary metering has been appropriately adjusted or compensated for losses. The primary voltage system for purposes of these provisions is defined as voltages from about 1,000 volts through 34.5 KV. Compensating metering adjustments for losses between secondary and primary will not be made for residential installations less than 10 KW. This implicitly recognizes that a higher loss factor would be appropriate in some cases for small secondary producers without requiring a completely unique rate schedule. Should a SPP be connected at greater than primary voltage the calculations and factors will be adjusted to reflect a lower loss adjustment factor. The provisions for connec-

[2]Our adoption of these principles is consistent with the important objective of utilizing, to the extent possible, the same methodology, computer resources, and assumptions in rate proceedings for SPP purchases that the Commission uses in rate proceedings for PSNH's retail sales. To the extent this is possible, several benefits will result, including consistency of assumptions, ease of understanding, reduced administrative costs, timely enhancements and reduced requirements for regulatory proceedings.

tions at greater than primary voltage will be implemented as necessary, but the specific rates for such cases have not been developed at this time.

[5] The *"Indirect Factor"* represents the combined effects of several potential adders, including: 1) an adjustment to translate the results from the PROSIM marginal cost methodology into the rigorous PROSIM method; 2) inventory costs; 3) working capital costs; and 4) operating and maintenance costs.

A comprehensive analysis of the merits of each adder would require time consuming investigation of several issues and is deemed to be impractical at this time. For purposes of this docket the Commission accepts a composite value of 1.08 for the indirect factor for both peak and off-peak periods, and for both short and long-term rates.[3]

B.4. *Payment for the Energy Component*

[6] The amount to be paid by PSNH to an SPP for the energy component will be calculated as follows: (energy component) × (energy produced during the time period for which payment is made). The rates and energy metered may be distinct by time of day as discussed herein at B.2.

B.5. *Capacity Component of the Rate*

[7] Although the magnitude of avoided capacity costs may be quite different depending upon the number of years to which the SPP is committed, several aspects of the capacity component of short and long-term rats are the same. The first is that the expression of the capacity values will remain in $/KW/YR and will no longer be translated into ¢/KWH and added to the energy rate. The Commission notes that the existing short term rate translated a capacity value of $22 per KW year into a ¢/KWH adder by spreading the $/KW year value over the number of hours SPPs were assumed to operate during the year. The Commission assumed a 50% capacity factor, with the resulting capacity payment of

$$0.5¢/\text{KWH} \frac{(\$22\quad)}{.50\times 8760}.$$

Payment on a per kilowatt hour basis meant that to the extent that a SPP had a capacity factor greater (or less) than 50%, and operated more (or less) than 4380 hours, it was being overpaid (or underpaid) for its capacity value. Payment on a $/KW/Yr basis will provide a more direct correlation between cost and rate components and facilitates administrative policies. The capacity component will be calculated in the following manner: (Marginal Cost of Capacity per KW per Year) × (Loss Adjustment Factor) = Capacity Component.

[8] The *"Marginal Cost of Capacity per KW"* is an annual cost based on estimated avoided costs of generation and transmission capacity. The specific assumptions and methodologies for quantifying these values for short and long-term rates will be discussed within each section.

The *"Loss Adjustment Factor"* for capacity reflects load losses at the time of peak loads. *See*, Exhibit 12, Attachment 2. This factor further recognizes the potential of SPPs to reduce system load and eventually PSNH's cost of meeting demand at times of peak load. Assuming that SPPs produce power at the point of interconnection, the magnitude of the peak load change at the generation and transmission levels of the system will be increased by a certain percentage relative to the value metered at the point of meter connection due to a loss factor. PSNH's loss study shows that the loss adjustment factor for the peak load hour applicable to SPPs is 1.159 at the generation level and 1.152 at the transmission level. The loss factors for capacity are higher than the 1.088 energy loss factor because they reflect values at time of peak load, rather than the average for the year.

B.6. *Payment of the Capacity Component*

[9] The amount to be paid by PSNH to a SPP for capacity will be calculated as follows: (Capacity Component) × (NHPUC Audit Value for the Site) × (Peak Reduction Factor). The annual payments for capacity will be made in twelve monthly payments.

[10] The *"NHPUC Audit Value"* is a site specific value expressing the estimated dependable capacity for the site, based on historical data (such as river flows for hydro) and the characteristics of the specific plant. *See*, Exh. 12, Attachment 3. The audits do and should reflect, to the extent possible, criteria similar to those imposed by the New England Power Pool ("NEPOOL") on PSNH generation units so that marginal capacity cost values, peak reduction factors and audit values are calculated on a consistent basis. The initial audit value, or if the initial audit value has changed the audit value in effect on January 1st of the year, determines the value to be used for determining payments during that calendar year. Following the initial audit, periodic reviews will be conducted. Audit values are expressed in kilowatts and will generally be a fraction of nameplate rated capacity; for example, a particular hydro site with a rated capacity of 900 KW may have an audit value of 500 KW. The audit procedures discussed in Commission Orders will apply. *See e.g.*, Re Small Energy Producers and Cogenerators (1982) 67 NH PUC 168; Re New Hampshire Electric Co-op., Inc. (1979) 64 NH PUC 244. In particular, it is the responsibility of the SPP to request the audit, and no capacity payments will be made prior to the assignment of an audit value nor will retroactive payments be made.

[11] The *"Peak Reduction Factor"* relates the amount of actual peak load reduction for an individual SPP or class of SPPs to the sum of their audit values. For those SPPs on Time-of-Day rates, the peak reduction will be calculated as the average KW during on-peak hours in the month of January and for SPPs on non Time-of-Day rates, the peak reduction will be calculated as the average KW of all hours during the month. The intent is eventually to group together SPPs with similar characteristics in contributing to peak load reduction. While actually metering the output of each SPP at time of peak load would measure its avoided capacity cost value, annual metering could be risky to individual producers in the event of unexpected outages, such as ice blockage at a hydro site. The process adopted herein is fairly calculated to determine the proper avoided capacity cost and then allocate the value to SPPs by class in a way that reduces individual risk.

The peak reduction factor for each class of SPPs will be based on a three-year average of the most recent actual data, measured during the month of January in each year, historically the month of highest demand on the PSNH system. The data will be updated annually as new data become available. Only sites having an assigned NHPUC audit value will be considered in the data base. A Commission objective is to maximize the SPP contribution at time of peak load

[3]The merits and specific values of each adder are further discussed in the Interim Order at 17-18 and in Exhibit 12 at 10-12.

and it is expected that over time the peak reduction factors will rise.

At present, the only group of SPPs with similar characteristics and sufficient historical data to be considered as a class is hydro. Certain other technologies (i.e., wood and biomass) have assigned NHPUC audit values but do not have sufficient historical data to be considered as a class. For those SPPs, the peak reduction factor will be calculated in the following manner. When the SPP has been audited, it will be assigned an estimated peak reduction factor by the Commission. The SPP's capacity payments will be based on that estimated peak reduction factor until the first January after the SPP is on line under a rate established in this docket. The estimated peak reduction factor will then be replaced with a factor based on the SPP's actual performance in that January and capacity payments for the following year will be made based on the actual peak reduction factor. In the following two Januaries, new peak reduction factors will be calculated from actual data and capacity payments will be made based on the two and then three year averages of the peak reduction factors. Thereafter, the peak reduction factor will be based on a three year rolling average. When there are sufficient similar facilities to develop class data, the peak reduction factor for all such similar SPPs will be based on class data.

For facilities which have neither an established audit procedure (such as wind or photovoltaic) nor sufficient data to establish peak reduction factors, the SPP's capacity payment will be based on the average KW calculated at time of peak load (average KW in January for the "all hours" rate or average on-peak KW for Time-of-Day ("TOD")).

The following table shows the peak reduction factors which will be used to initiate the process of implementing short and long-term rates for hydro facilities:

TABLE 1

Type of Facility	*Year 1*	*Year 2*	*Year 3*	*3 Year Average*
Hydro - TOD	.80	.80	.80	.80
Hydro - Non TOD	.70	.70	.70	.70

The factors are intended to be updated annually and the average of the most recent three-year period will be applied in a calendar year. Because the actual data now available were developed before an incentive to produce at time of peak load existed, the initial factors have been developed with a degree of judgement. As data become available beginning with January 1985, actual data will replace the estimated data. Thus, the three-year average values for 1985 will be calculated with two estimated values and one actual value. By 1987, the reduction factors will be based on actual data for January 1985, January 1986 and January 1987. The most recent factor will continue to be used in the first months of a year and then adjusted when the current year January data are available. Payments for the Capacity Component will be adjusted so that the proper annual payment is paid and any over or under payment in the early months of a year is removed.

Larger SPPs who wish to avoid the procedure of being grouped by class may contract with PSNH to allow NEPOOL dispatch and NEPOOL capacity credit to PSNH for the specified SPP site. The

specific details and values for the site would have to be determined by the parties to the private contract.

B.7. *Interconnection Policy*

All prior Commission Orders relative to interconnection procedures continue to apply except to the extent they are inconsistent with provisions contained herein. SPPs are directed to contact PSNH for an Interconnection Study prior to any commitments and at least 45 days prior to filing for the rate, and must file an Interconnection Agreement signed by the SPP as part of the rate filing. As previously noted, SPPs are responsible for all costs reasonably incurred by PSNH as a result of interconnection. Those costs include costs of installation of equipment elsewhere on the utility's system necessitated by the interconnection. In the case of a number of SPPs interconnecting in the same area, the costs will be charged on an incremental basis so that the last SPP on line is responsible for all costs to interconnect the facility and no retroactive cost allocation to facilities on line is permitted.

B.8. *Eligible Facilities*

Eligible facilities are Qualifying Small Power Producers and Qualifying Cogenerators as defined in LEEPA and PURPA.[4] Until such time as the Commission establishes differing requirements with respect to

1) minimum size, fuel use, fuel efficiency and ownership for Qualifying Cogenerators and
2) fuel use, fuel efficiency, reliability and ownership for Qualifying Small Power Producers

the FERC rules and regulations implementing PURPA which govern these matters will continue to apply.

In addition, neither facilities less than 15 KW nor residential facilities will be eligible for the long-term rate.

C. *Short-Term Rates*

C.1. *Overview and Administrative Provisions*

The short-term energy rate will be set every six months during Energy Cost Recovery Mechanism ("ECRM") proceedings. Except for the marginal energy cost, which will be redetermined in each ECRM proceeding, the methodology and all other factors will be held constant during ECRM proceedings. Factors other than marginal energy cost, such as loss adjustment factors, the indirect factor and capacity values, will be revised when data from new studies become available in more comprehensive, non-ECRM dockets.

The parties have filed a copy of an Interconnection Agreement to be required of SPPs electing to take the short term rate. *See*, Exh. 12, Attachment 5. The Commission's acceptance of the Stipulated Recommendations includes acceptance of the filed Interconnection Agreement. The Commission notes that the Agreement is essentially the same as that being used currently except that the period of notice has been extended from 6 months to one year to provide adequate time for PSNH to plan in the spring to avoid capacity costs in the following January. PSNH is directed to allow SPPs currently on the LEEPA short-term contracts to waive the notice period for release from their present agreement for the sole purpose of allowing the SPP to elect either

[4] The Commission acknowledges PSNH's reservation of rights to argue at a later time that the eligibility criteria adopted in this Order should be narrowed. *See*, Exh. 12 at 18.

the new short or long-term arrangements adopted herein. The Company is also directed to make available copies of the Interconnection Agreement upon request.

No formal filing requirements will be required of SPPs electing the short-term rate. The SPP will execute the Interconnection Agreement with PSNH and PSNH will file the Agreement with the Commission.

C.2. *Energy Component of the Short-Term Rate*

The energy component for the short term rate will be calculated from marginal energy cost data using the same assumptions and the same PROSIM scenario used to calculate the ECRM rate. The rate will therefore be calculated for the two periods January to June and July to December. The rates will be forward looking and will not be subject to reconciliation. However, PSNH is directed to monitor and report to the Commission the actual marginal energy costs using standard PSNH data to ensure that any deviations between actual and forecast marginal energy cost values are small and adequately explained.

While the rate for each six month period will be set during the ECRM proceedings, the initial short term rate for the period of July-December 1984 will be:

TABLE 2

Hourly Period	*Marginal Energy Cost (¢/KWH)*	*Loss Adjustment Factor*	*Indirect Factor*	*Total Energy Component (¢/KWH)*
All Hours	5.521	1.086	1.08	6.48
On-Peak	6.184	1.105	1.08	7.38
Off-Peak	4.990	1.072	1.08	5.78

Source: Public Service Co. of New Hampshire, Docket No. DR 84-128, Exhibit 13.

C.3. *Capacity Component of Short-Term Rate*

As noted herein at Section B.5, the capacity component of the rates will vary depending on the length of time to which the SPP is committed. There may be opportunity for short-term generation capacity savings depending on the secondary market in New England. SPPs can produce a system value by reducing system peak load and PSNH's resulting short-term Capability Responsibility. *See,* Exh. 12, Attachment 1. This system peak load reduction can lead to avoided costs in the near term if PSNH is able to avoid purchases or increase sales of capacity.

Until Seabrook I comes on line, PSNH will generally need to contract for purchased capacity to meet peak demand. At the present time, PSNH estimates in the spring of each year how much additional capacity it will need in order to meet peak demand in the following January. PSNH then contracts to supply this predetermined amount of additional capacity. Under current circumstances, PSNH has a capacity deficiency and a 1984 short-term capacity value (net of fuel savings) of $52.67 per KW.

The calculation of the short-term capacity cost is based on results for the year 1984 in the "PSNH System Planning Response Marginal Cost Methodology and Results" calculations found in Re Public Service Co. of New Hampshire, *supra.* The short-term capacity cost

is determined by dividing the 1984 estimate ($2633.30) by 50 KW. The resulting value of $52.67 per KW will remain constant until it is revised in future non-ECRM proceedings. This value includes avoided transmission wheeling costs and an adjustment for reserves.

Short-term commitments of only 1 year will not allow PSNH to avoid construction of transmission lines since thes projects require several years of lead time. Thus, no avoided transmission costs are included in the short-term rate other than those associated with wheeling.

Applying a generation loss adjustment factor of 1.159, as discussed herein at Section B.5, produces a total annual capacity component of $61.04 per KW ($52.67 per KW × 1.159). The Commission notes, however, that the short-term value may drop sharply when Seabrook I comes on line.

C.4. *Payment of Energy and Capacity Components*

Payment for the energy component will be as discussed herein at Section B.4. The annual amount paid to a SPP for capacity will be the product of the capacity component, times the audit value of the site, times the appropriate peak reduction factor as discussed herein at Section B.6. *See also,* Exh. 12, Attachment 4. For example, a hypothetical hydro site on the Time-of-Day rate would be eligible for current short-term capacity payments equal to $61.04 × 500 KW (audit value) × .80 (peak reduction factor) = $24,416, divided into 12 monthly payments. For SPPs electing the short-term rate, only sites on line by January 1st of the year will receive capacity payments during that calendar year. Sites on line after January 1st will receive their first capacity payments the following year.

D. *Long Term Rates*

D.1. *Overview and Administrative Provisions*

This Order incorporates much of the methodology initially prescribed in the interim Order. In the following sections we note certain revisions or additions to the procedures of the Interim Order. The parties are directed to develop a complete description of the procedures to be used in calculating and obtaining a long-term rate, which can serve as a complete and easily understood explanation to SPPs.

D.2. *Assumptions Regarding PSNH and Seabrook for Purposes of this Docket*

As discussed herein at Section B, this Order is based on the premise that SPP rate-setting should use the same methodology and assumptions for calculating avoided costs that are used to calculate marginal costs in setting retail rates. The marginal cost methodology referred to herein at Section B.1. requires detailed assumptions and forecasts of several factors for precise calculations. However, because of the current uncertainties surrounding PSNH and Seabrook, the Commission is unable to select a single most likely scenario or set of assumptions for purposes of calculating long-term avoided costs. Thus, we accept the recommendation of the parties who arrived at a resolution through both analytical and judgmental weighting of several possible scenarios. This procedure is quite unique, but is a necessary and innovative approach to address some areas which are currently in considerable doubt.

The three scenarios weighted by the parties are as follows:

Case 2 with both Seabrook Units (7/86, 12/90)

Case 1 with one Seabrook Unit (7/86)
Case 0 with no Seabrook Units

Several other scenarios such as different in-service dates for Seabrook, high and low fuel price scenarios, and other modifications of assumptions were discussed by the parties. The parties agreed, and the Commission accepts, that by applying various weights to each of the three scenarios (Cases 0, 1, and 2), impacts under other assumptions and scenarios (*e.g.*, a completion date later than July 1986 for Seabrook I in Case 1) could be considered, and these are ultimately reflected in the final weighted series of values shown in the Stipulated Case. The Stipulated case reflects a weighting of 25% for Case 2, 50% for Case 1, and 25% for Case 0.[5]

D.3. *Applicable Long Term Rates*

The following table displays the avoided costs relevant to long term SPP rates which result from the weighted case stipulated by the parties and accepted by the Commission. Column A contains values for the Total Capacity Component. Column B-ALL, B-ON, and B-OFF display the total energy component for "all hours", peak and off-peak rates respectively.

TABLE 3

SUMMARY OF AVOIDED COSTS RELEVANT TO SPP LONG TERM RATES

Year	*COLUMN A* *Total Loss Adjusted Capacity Costs* $/KW/YR	*COLUMN B - ALL* *Avoided Cost of Energy After Adjustments* cents/KWH	*COLUMN B - ON* *Avoided Cost of Energy After Adjustments* cents/KWH	*COLUMN B - OFF* *Avoided Cost of Energy After Adjustments* cents/KWH
1984	49.25	6.23	7.21	5.46
1985	52.55	6.23	7.30	5.46
1986	56.07	5.88	6.58	5.25
1987	59.83	5.93	6.91	5.25
1988	63.83	6.46	7.48	5.57
1989	68.11	6.93	7.87	6.27
1990	72.67	7.67	8.65	6.88
1991	77.54	8.08	9.25	7.17
1992	82.74	9.22	10.53	8.21
1993	88.28	10.19	11.73	9.06
1994	94.20	11.57	13.17	10.30
1995	100.51	12.84	15.26	11.03
1996	107.24	13.89	16.49	11.87
1997	114.43	15.54	18.43	13.32
1998	122.10	16.92	19.99	14.60
1999	130.28	19.56	23.31	16.63
2000	139.00	21.18	24.99	18.29
2001	148.32	21.94	25.32	19.45
2002	158.25	25.15	29.42	21.86
2003	168.86	28.26	32.98	24.67
2004	180.17	28.64	33.88	24.41
2005	192.24	32.58	38.24	28.30
2006	205.12	35.90	42.76	30.68
2007	218.87	38.54	45.96	32.83
2008	233.53	45.21	54.31	38.23
2009	249.18	46.53	55.45	39.71
2010	265.87	48.50	57.61	40.93
2011	283.69	52.35	62.36	44.79
2012	302.69	55.78	66.13	47.86
2013	322.97	63.01	74.93	53.84
2014	344.61	67.23	79.95	57.45
2015	367.70	71.74	85.31	61.30

[5]The detail on Cases 0, 1, 2 and the Stipulated case may be found at Exhibit 12, Attachment 7.

The annual data in Table 3 provides the basis for selecting and determining a rate for each SPP site. The rate may be simply the schedule tariff, providing for annual energy and capacity payment as shown, or the rate may be varied, subject to the conditions discussed below.

Obligations of 5 to 30 years will be permitted. The initial year of the long-term rate obligation may not be more than four years from the time of filing. SPPs may select as their rates the values shown above, levelized values for the years of their obligation, or some rate in between, so long as the cumulative net present values, discounted appropriately, do not exceed the values shown in Table 3.

For facilities on line before September 1, the year in which the facility first supplies power under the long-term rate is considered to be the initial year for rate calculations. For facilities on line after September 1, the following year will be considered as the initial year. All facilities will receive annual rate changes (if any) of their elected rate schedule in the month of their anniversary date (the date on which the SPP supplied power under the long-term rate). Any SPP may elect the short-term rate until September 1 to obtain rates using the following year as the initial year and an anniversary date commensurate with the start of the long-term rate.

Calculations for rates which vary from the schedule in Table 3 must use the Net Present Value method prescribed in the Interim Order. The discount factor used is 13.43%; a value based on a calculation of PSNH's long-term cost of capital. *See,* Exh. 12, Attachment 9. An average of values for several time periods was calculated to produce a single discount factor in order to reduce the administrative problems which occur when multiple discount rates are used. The value is accepted strictly for purposes of this docket.

The Capacity Component includes avoided costs for generation and transmission capacity. These calculations assume a permanent decrement of 50 MW to peak load and reflect a levelizing of costs for 20 years using an economic carrying charge. This method removes, to a large extent, the lumpiness of annual costs associated with transmission and generation plant. However, when the load decrements are of shorter duration (*i.e.*, when SPPs obligate themselves for less than 20 years), the opportunity to avoid costs is reduced and the values of the avoided costs are also reduced. To reflect this, the capacity values will be reduced by 5 percent for each year that the rate term is less than 20 years (*e.g.*, a 10 year rate would use 50 percent of the capacity values). For shorter term rates the SPP may elect to be paid based on the long-term energy component and the short-term capacity component. As discussed herein at Section C.3, the short-term capacity component will be set from time to time. The rate is currently set at $61.04/KW/YR, but may be substantially less in later years.

For informational purposes, the Commission has calculated the levelized value of obligations of 10, 15, 20 and 30 years, commencing in 1984, 1985, and 1986. The calculation includes in the capacity value the 5 percent discount per year that the rate term is less than 20 years.

TABLE 4
ENERGY — ALL HOURS ¢/KWH

Start	1984	1985	1986
Term			
10	6.86	7.23	7.72
15	7.95	8.50	9.16
20	9.08	9.73	10.51
30	11.27	11.97	12.75

CAPACITY $/KWYr.

Start	1984	1985	1986
Term			
10*	31.39	33.49	35.73
15**	52.13	55.63	59.36
20	75.43	80.48	85.87
30	85.92	90.95	96.22

*discounted 50%
**discounted 25%
See also, Exh. 12, Attachment 8.

Long-term front-end-loaded rates are subject to a "ceiling" provision (similar to the 9¢ ceiling of the Interim Order), which must be factored into the rate calculation. A maximum of 90 percent of the levelized rate (for both energy and capacity components) is allowed for the first three years of long-term rates which commence prior to July 1, 1989. After the first three years, rates may rise to a re-calculated levelized value (based on net present value for the remainder of the term) which compensates for the original ceiling. (For rates commencing after July 1, 1989, levelized values for all years of the obligation may be selected by the SPP.) This provision addresses the concern that retail ratepayers will pay rates for SPP energy in the near term in excess of short-term avoided costs.[6] An exemption from the ceiling provision may be obtained from the Commission. To qualify, the SPP must demonstrate that the full levelized rate is necessary to permit development of the site.

For SPPs requesting a degree of levelizing in rates, the following measures are included to provide for additional ratepayer protection:

1) Project life must be equal to or greater than the rate term.
2) Assurances must be provided that the level of annual output will be adequately maintained by the SPP, so that PSNH (and ratepayers) may recoup the full Net Present Value of payments.
3) For rate terms longer than 20 years, a surety bond or a junior lien on the project must be given to cover the "buy out" value at the site.

The provisions adopted in this section for front-end loading and levelizing are intended to stimulate SPP site development and will be applied only once to each site.

The buy out provision of the Interim Order will be modified to allow an SPP to buy out of the rate, provided that the SPP must continue to sell its output to PSNH for the term of the SPP's original commitment or the term of the new rate, whichever is greater. The buy out will only apply to the energy component of the rate. The capacity component and other terms and conditions of the original rate will remain in effect. To exercise the buy out, a SPP must provide 60 days notice and pay PSNH the difference between the energy component payments and the amount which would have been paid if the annual values of Table 3 were applied. The annual differences will be increased by 13.43% compounded annually to the year of buy out to provide appropriate buy out present value.

D.4. *Filing Requirements*

The same filing requirements as provided in the Interim Order will apply except as modified by this Order. Rate calculations must be filed on the worksheets provided herein as Attachment 1.

E. *Implementation of the Short and Long-Term Rates*

The procedures and the new rates adopted herein will be implemented with the effective date of this Order. The short term rate will be established for July - December 1984 based on the findings from Re Public Service Co. of New Hampshire (1984) 69 NH PUC 344. It is intended that avoided cost data will be updated annually by the Company and reviewed by the Commission to determine the extent, if any, to which the rates should be revised. With respect to long-term arrangements, any such changes will be applied prospectively only; those SPPs with existing long-term arrangements will continue to be governed by those arrangements.

The implementation of this Order is subject to various lead times required by PSNH for such matters as purchasing and installing time-of-day meters, developing and implementing provisions of interconnection studies, and other administrative procedures. It is the responsibility of SPPs to contact PSNH prior to any commitments to ensure that the costs and scheduling requirements of such matters are recognized.

Because this Order implements many new procedures regarding SPP rates, it is anticipated that questions of intent or interpretation will arise. We adopt the recommendation of the Parties that, where possible, informal discussion, rather than formal litigation or arbitration, will be an initial method of resolving such questions. The parties are directed to report to the Commission on the outcome of such discussions.

F. *Short Term Bridge Rate*

[12] As previously noted, the Stipulated Recommendations (Exhibit 12) contained a provision which created a short term bridge rate for certain eligible SPPs. The parties were not able to agree on whether this particular recommendation

[6] Of course, levelized rates, by definition, will allow ratepayers the benefit of rates which are lower than the short-term avoided cost for SPP power purchased at the tail end of the obligation.

should be adopted; PSNH, Staff and CLF recommended that the short term bridge rate should be rejected by the Commission, while the remainder of the parties recommended adoption. All signatories to the Stipulated Recommendations agreed that the disposition of the issue was to be left to the Commission; Commission rejection of the provision would not affect the remainder of the Stipulated Recommendations.

As described in Exhibit 12, Section II.E., the Short Term Bridge Rate would allow eligible SPPs to continue to receive the short term rates established by the Commission in Re Small Energy Producers and Cogenerators (1980) 65 NH PUC 291 for a period of 5 years. That rate is 7.7¢/KWH for energy and 8.2¢/KWH for energy and capacity (65 NH PUC at p. 300). Eligible SPPs would be defined as those SPPs who made a substantial capital commitment between the June 18, 1980 date of Re Small Energy Producers and Cogenerators, *supra*, and the September 16, 1982 date of Re Granite State Electric Co. (1981) 121 NH 787, 435 A2d 119.

Those parties favoring the adoption of the short term bridge rate justify that rate on the basis of the reliance of certain SPPs on a provision of the Commission's Order in Docket DE 79-208 which established the 7.7¢/8.2¢ rate as a minimum rate (65 NH PUC at p. 298); a provision which was explicitly reversed by the Court in Re Granite State Electric Co., *supra*. This rationale was expanded in Exhibit 12 which stated at 23:

> As a result of the decision in DE 79-208, it was reasonable to expect that the short-term rate would not be reduced. In addition to the Commission's Order, establishing a lifetime guaranteed minimum rate, the State of New Hampshire had experienced a continuing series of escalations in the price of oil. As a result, a small number of Small Power Producers did make substantial capital commitments relying upon this Commission's Order and the expectation that oil prices would not decrease. As a result, Small Power Producers viewing their existing cash flow data, did commit to replacement equipment and improved facilities for greater production reliability and/or for new facilities and equipment for additional production. These improved facilities, whether for greater service continuity or for increased production, were based upon the Commission's Order and the Small Power Producer's financial ability.
>
> . . . Since the rate set by the Commission in DE 79-208 has been in existence for over four years without a change, it is reasonable to expect that the Small Power Producers did not view this rate as a (sic) annually adjusted rate. As such, Small Power Producer's relied on rate continuity as a basis for the improvement and upgrading of facilities and equipment. The unique and short history of this concept is such so that it is reasonable to expect that these Small Power Producers would rely upon the rate or, at the worst, only slight modifications in the short-term rate. Although the rate was set as a year to year rate, Small Power Producers recognized it as more like a fixed rate than a rate fluctuating annually.

The parties opposing the adoption of the short term bridge rate base their position on the fact that the rate is higher than PSNH's avoided cost (*see e.g.*, the short term rate established, *supra*, at p. 362). Thus, approval of the bridge rate means that the Commission would be allowing PSNH's ratepayers to subsidize eligible SPPs. Such a subsidy is improper, it was argued, because the SPPs have the alternative of continuing to receive rates that are in the 7.7¢/8.2¢ range, or higher, by obligating themselves to PSNH under the long-term rate provisions established in this proceeding.

Our analysis of the issue leads us to conclude that it would not be in the public interest to adopt the short term bridge rate. Although we recognize that many eligible SPPs were industry "pioneers" who deserve the appreciation of this Commission and the public for their courage and foresight, we believe we should consider rates which involve ratepayer subsidies only where the evidence conclusively demonstrates that such rates are necessary and in the public interest.[7] That evidence does not exist here.

The evidence which does exist reflects the fact that SPPs who would be eligible for the short term bridge rate would be able to receive rates which either equal or exceed the short term bridge rate by obligating themselves to long term arrangements pursuant to the terms of this Order. The evidence of record also reflects the fact that SPPs who would be eligible for the short term bridge rate do not wish to engage in a long term arrangement because they are suspicious of PSNH. Our analysis of this evidence is that it simply cannot be considered as a basis for allowing a rate which exceeds avoided cost. Certain SPPs may or may not have good reason to be suspicious of PSNH, but we cannot base our decision-making on unsupported suspicion, particularly where an otherwise available arrangement is the one established by the Commission in this Order. Since we believe that the long term alternative would meet the requirements of all concerned persons and since we have not been presented with a good reason for the rejection of that alternative by certain SPPs, we must conclude that a rate which exceeds avoided cost is not in the public interest. We therefore reject Section II.E. of Exhibit 12, Stipulated Recommendations.

III. *CONCLUSION*

After review, we have found that the Stipulated Recommendations set forth in Exhibit 12 (with the exception of the recommendation contained at Section II.E.) are just, reasonable, in the public interest and consistent with the requirements of LEEPA and PURPA. We have therefore adopted all recommendations, with the exception of Section II.E. of Exhibit 12. We cannot conclude, however, without commending our Staff and all the parties for their efforts in this docket. The issues resolved in this docket were difficult and the recommendations submitted to us reflect extraordinary good faith efforts by all participants over an extended period of time.

Our Order will issue accordingly.

SUPPLEMENTAL ORDER

Upon review of the foregoing Report, which is made a part hereof; it is

ORDERED, that short term and long term rates be, and hereby are, established for the purchase of energy, capacity or

[7]As noted, *supra*, at p. 354, the provisions of this Order are designed to encourage economically efficient SPPs while being just and reasonable to PSNH's ratepayers. The only way these two standards can be reconciled is to define economically efficient SPPs as those SPPs who can produce electricity at a cost which is at or below the avoided cost of the purchasing utility. We do not believe that either LEEPA or PURPA embody policies which would require us to encourage SPP development which is not economically efficient.

both by Public Service Company of New Hampshire from Small Power Producers as provided in the foregoing Report; and it is

FURTHER ORDERED, that the terms and conditions of the purchase of energy, capacity or both by Public Service Company of New Hampshire from Small Power Producers shall be set forth in the foregoing Report; and it is

FURTHER ORDERED, that this docket is closed.

By order of the Public Utilities Commission of New Hampshire this fifth day of July, 1984.*

*Chairman McQuade was absent on the date of the decision, but will review the decision upon his return. In the event he concurs, his signature will be added herewith.

Attachment 1

Long Term Rate Worksheet — 1984 Present Value Calculation — Energy - All Hours

Year	Avoided Energy Cost ¢/KWH	Present Value Divisor	Present Value of Avoided Energy Costs 1984 $	Contract Price ¢/KWH	Present Value of Contract Price		Cumulative P.V. Avoided Energy Costs 1984 Start	Cumulative P.V. Contract Price 1984 Start	Cumulative P.V. Avoided Energy Costs 1985 Start	Cumulative P.V. Contract Price 1985 Start	Cumulative P.V. Avoided Energy Costs 1986 Start	Cumulative P.V. Contract Price 1986 Start	Cumulative P.V. Avoided Energy Costs 1987 Start	Cumulative P.V. Contract Price 1987 Start
1984	6.23	1.0000	6.230				6.230							
85	6.23	1.1343	5.492				11.722		5.492					
86	5.88	1.2866	4.570				16.293		10.063		4.570			
87	5.93	1.4594	4.063				20.356		14.126		8.633		4.063	
88	6.46	1.6554	3.092				24.258		18.028		12.536		7.966	
89	6.93	1.8778	3.690				27.949		21.719		16.226		11.656	
1990	7.67	2.1299	3.601				31.550		25.320		19.827		15.257	
91	8.08	2.4160	3.344				34.894		28.664		23.172		18.602	
92	9.22	2.7405	3.364				38.259		32.029		26.536		21.966	
93	10.19	3.1085	3.278				41.537		35.307		29.814		25.244	
94	11.57	3.5260	3.281				44.818		38.588		33.096		28.525	
95	12.84	3.9995	3.210				48.028		41.798		36.306		31.736	
96	13.89	4.5366	3.062				51.090		44.860		39.368		34.798	
97	15.54	5.1459	3.020				54.110		47.880		42.388		37.818	
98	16.92	5.8370	2.899				57.009		50.779		45.286		40.716	
99	19.56	6.6209	2.954				59.963		53.733		48.241		43.671	
2000	21.18	7.5101	2.820				62.783		56.553		51.061		46.491	
01	21.94	8.5187	2.576				65.359		59.129		53.636		49.066	
02	25.15	9.6628	2.603				67.962		61.732		56.239		51.669	
03	28.26	10.9605	2.578				70.540		64.310		58.818		54.247	
04	28.64	12.4325	2.304				72.844		66.614		61.121		56.551	
05	32.58	14.1022	2.310				75.154		68.924		63.431		58.861	
06	35.90	15.9961	2.244				77.398		71.168		65.676		61.106	
07	38.54	18.1444	2.124				79.522		73.292		67.800		63.230	
08	45.21	20.5812	2.197				81.719		75.489		69.996		65.426	
09	46.53	23.3452	1.993				83.712		77.482		71.990		67.419	
2010	48.50	26.4805	1.832				85.544		79.314		73.821		69.251	
11	52.35	30.0368	1.743				87.286		81.056		75.564		70.994	
12	55.78	34.0708	1.637				88.924		82.694		77.201		72.631	
13	63.01	38.6465	1.630				90.554		84.324		78.832		74.261	
14	67.23	48.8367	1.534				92.088		85.858		80.365		75.795	
15	71.74	49.7240	1.443				93.530		87.300		81.808		77.238	

Long Term Rate Worksheet — 1984 Present Value Calculation — Energy - On Peak

Year	Avoided Energy Cost ¢/KWH	Present Value Divisor	Present Value of Avoided Energy Costs 1984 $	Contract Price ¢/KWH	Present Value of Contract Price		Cumulative P.V. Avoided Energy Costs 1984 Start	Cumulative P.V. Contract Price 1984 Start	Cumulative P.V. Avoided Energy Costs 1985 Start	Cumulative P.V. Contract Price 1985 Start	Cumulative P.V. Avoided Energy Costs 1986 Start	Cumulative P.V. Contract Price 1986 Start	Cumulative P.V. Avoided Energy Costs 1987 Start	Cumulative P.V. Contract Price 1987 Start
1984	7.21	1.0000	7.210				7.210							
85	7.30	1.1343	6.436				13.646		6.436					
86	6.58	1.2866	5.114				18.760		11.550		5.114			
87	6.91	1.4594	4.735				23.495		16.285		9.849		4.735	
88	7.48	1.6554	4.519				28.013		20.803		14.368		9.253	
89	7.87	1.8778	4.191				32.204		24.994		18.559		13.444	
1990	8.65	2.1299	4.061				36.266		29.056		22.620		17.506	
91	9.25	2.4160	3.829				40.094		32.884		26.449		21.334	
92	10.53	2.7405	3.842				43.937		36.727		30.291		25.177	
93	11.73	3.1085	3.774				47.710		40.500		34.064		28.950	
94	13.17	3.5260	3.735				51.445		44.235		37.800		32.685	
95	15.26	3.9995	3.815				55.261		48.051		41.615		36.501	
96	16.49	4.5366	3.635				58.896		51.686		45.250		40.136	
97	18.43	5.1459	3.581				62.477		55.267		48.831		43.717	
98	19.99	5.8370	3.425				65.902		58.692		52.256		47.142	
99	23.31	6.6209	3.521				69.422		62.212		55.777		50.663	
2000	24.99	7.5101	3.328				72.750		65.540		59.104		53.990	
01	25.32	8.5187	2.972				75.722		68.512		62.077		56.962	
02	29.42	9.6628	3.045				78.767		71.557		65.121		60.007	
03	32.98	10.9605	3.009				81.776		74.566		68.130		63.016	
04	33.88	12.4325	2.725				84.501		77.291		70.855		65.741	
05	38.24	14.1022	2.712				87.213		80.003		73.567		68.453	
06	42.76	15.9961	2.673				89.886		82.676		76.240		71.126	
07	45.96	18.1444	2.533				92.419		85.209		78.773		73.659	
08	54.31	20.5812	2.639				95.058		87.848		81.412		76.298	
09	55.45	23.3452	2.375				97.433		90.223		83.787		78.673	
2010	57.61	26.4805	2.176				99.608		92.398		85.963		80.849	
11	62.36	30.0368	2.076				101.685		94.475		88.039		82.925	
12	66.13	34.0708	1.941				103.626		96.416		89.980		84.866	
13	74.93	38.6465	1.939				105.564		98.354		91.919		86.804	
14	79.95	43.8367	1.824				107.388		100.178		93.743		88.628	
15	85.31	49.7240	1.716				109.104		101.894		95.458		90.344	

Long Term Rate Worksheet — 1984 Present Value Calculation — Energy - Off Peak

Year	Avoided Energy Cost ¢/KWH	Present Value Divisor	Present Value of Avoided Energy Costs 1984 $	Contract Price ¢/KWH	Present Value of Contract Price	Cumulative P.V. Avoided Energy Costs 1984 Start	Cumulative P.V. Contract Price 1984 Start	Cumulative P.V. Avoided Energy Costs 1985 Start	Cumulative P.V. Contract Price 1985 Start	Cumulative P.V. Avoided Energy Costs 1986 Start	Cumulative P.V. Contract Price 1986 Start	Cumulative P.V. Avoided Energy Costs 1987 Start	Cumulative P.V. Contract Price 1987 Start
1984	5.46	1.0000	5.460			5.460							
85	5.46	1.1343	4.814			10.274		4.814					
86	5.25	1.2866	4.081			14.354		8.894		4.081			
87	5.25	1.4594	3.597			17.951		12.491		7.678		3.597	
88	5.57	1.6554	3.365			21.316		15.856		11.043		6.962	
89	6.27	1.8778	3.339			24.655		19.195		14.382		10.301	
1990	6.88	2.1299	3.230			27.885		22.425		17.612		13.531	
91	7.17	2.4160	2.968			30.853		25.393		20.580		16.499	
92	8.21	2.7405	2.996			33.849		28.389		23.575		19.495	
93	9.06	3.1085	2.915			36.763		31.303		26.490		22.409	
94	10.30	3.5260	2.921			39.685		34.225		29.411		25.331	
95	11.03	3.9995	2.758			42.443		36.983		32.169		28.088	
96	11.87	4.5366	2.616			45.059		39.599		34.785		30.705	
97	13.32	5.1459	2.588			47.647		42.187		37.374		33.293	
98	14.60	5.8370	2.501			50.149		44.689		39.875		35.795	
99	16.63	6.6209	2.512			52.660		47.200		42.387		38.306	
2000	18.29	7.5101	2.435			55.096		49.636		44.822		40.742	
01	19.45	8.5187	2.283			57.379		51.919		47.106		43.025	
02	21.86	9.6628	2.262			59.641		54.181		49.368		45.287	
03	24.67	10.9605	2.251			61.892		56.432		51.619		47.538	
04	24.41	12.4325	1.963			63.856		58.396		53.582		49.502	
05	28.30	14.1022	2.007			65.862		60.402		55.589		51.508	
06	30.68	15.9961	1.918			67.780		62.320		57.507		53.426	
07	32.83	18.1444	1.809			69.590		64.130		59.316		55.236	
08	38.23	20.5812	1.858			71.447		65.987		61.174		57.093	
09	39.71	23.3452	1.701			73.148		67.688		62.875		58.794	
2010	40.93	26.4805	1.546			74.694		69.234		64.420		60.340	
11	44.79	30.0368	1.491			76.185		70.725		65.912		61.831	
12	47.86	34.0708	1.405			77.590		72.130		67.316		63.236	
13	53.84	38.6465	1.393			78.983		73.523		68.709		64.629	
14	57.45	43.8367	1.311			80.293		74.833		70.020		65.939	
15	61.30	49.7240	1.233			81.526		76.066		71.253		67.172	

Long Term Rate Worksheet — 1984 Present Value Calculation — Capacity

Year	Avoided Capacity Cost ¢/KWH	Present Value Divisor	Present Value of Avoided Capacity Costs 1984 $	Contract Price ¢/KWH	Present Value of Contract Price	Cumulative P.V. Avoided Capacity Costs 1984 Start	Cumulative P.V. Contract Price 1984 Start	Cumulative P.V. Avoided Capacity Costs 1985 Start	Cumulative P.V. Contract Price 1985 Start	Cumulative P.V. Avoided Capacity Costs 1986 Start	Cumulative P.V. Contract Price 1986 Start	Cumulative P.V. Avoided Capacity Costs 1987 Start	Cumulative P.V. Contract Price 1987 Start
1984	49.25	1.0000	49.250			49.250							
85	52.55	1.1343	46.328			95.573		46.328					
86	56.07	1.2866	43.580			139.153		89.908		43.580			
87	59.83	1.4594	40.996			180.151		130.904		84.576		40.996	
88	63.83	1.6554	38.559			218.713		169.463		123.135		79.555	
89	68.11	1.8778	36.271			254.984		205.734		159.406		115.826	
1990	72.67	2.1299	34.119			289.103		239.853		193.525		149.945	
91	77.54	2.4160	32.094			321.198		271.948		225.619		182.039	
92	82.74	2.7405	30.192			351.389		302.139		255.811		212.231	
93	88.28	3.1085	28.400			379.789		330.539		284.211		240.631	
94	94.20	3.5260	26.716			406.505		357.255		310.926		267.346	
95	100.51	3.9995	25.131			431.635		382.385		336.057		292.477	
96	107.24	4.5366	23.639			455.274		406.024		359.696		316.116	
97	114.43	5.1459	22.237			477.511		428.261		381.933		338.353	
98	122.10	5.8370	20.918			498.429		449.179		402.851		359.271	
99	130.28	6.6209	19.677			518.106		468.856		422.528		378.948	
2000	139.00	7.5101	18.508			536.615		487.365		441.037		397.457	
01	148.32	8.5187	17.411			554.026		504.776		458.448		414.868	
02	158.25	9.6628	16.377			570.403		521.153		474.825		431.245	
03	168.86	10.9605	15.406			585.809		536.559		490.231		446.651	
04	180.17	12.4325	14.492			600.301		551.051		504.723		461.143	
05	192.24	14.1022	13.632			613.933		564.683		518.355		474.775	
06	205.12	15.9961	12.823			626.756		577.506		531.178		487.598	
07	218.87	18.1444	12.063			638.819		589.569		543.241		499.661	
08	233.53	20.5812	11.347			650.166		600.916		554.588		511.008	
09	249.18	23.3452	10.674			660.840		611.590		565.261		521.681	
2010	265.87	26.4805	10.040			670.880		621.630		575.302		531.722	
11	283.69	30.0368	9.445			680.325		631.075		584.746		541.166	
12	302.69	34.0708	8.884			689.209		639.959		593.631		550.051	
13	322.97	38.6465	8.357			697.566		648.316		601.988		558.408	
14	344.61	43.8367	7.861			705.427		656.177		609.849		566.269	
15	367.70	49.7240	7.395			712.822		663.572		617.244		573.664	

[N.H.] A local exchange telephone carrier was conditionally authorized to install, maintain and operate aerial telephone plant over and across public waters where (1) the plant was necessary to ensure the continuity of telephone service during the demolition and reconstruction of a bridge, (2) the carrier had assured the commission that it had coordinated the construction of the plant with the New Hampshire Department of Transportation and had obtained all necessary easements, and (3) the carrier had indicated that the plant would be removed and relocated within the structure of the bridge upon completion of the reconstruction; authorization was conditioned upon the public having an opportunity to respond and upon all construction meeting the requirements of the National Electric Safety Code.

By the COMMISSION:

ORDER

WHEREAS, on March 16, 1988, the New England Telephone & Telegraph Company, Inc. (NET) filed with this Commission its petition seeking license under RSA 371:17 to install, maintain and operate aerial telephone plant over and across the public waters of the Connecticut River between Walpole, New Hampshire, and Westminster, Vermont; and

WHEREAS, such plant comprises temporary facilities to serve the public's needs during demolition and reconstruction of a bridge along Route 123; and

WHEREAS, said temporary facility is necessary to ensure the continuity of telephone service of subscribers in the Walpole/Westminster area during that construction; and

WHEREAS, NET has assured the Commission that its construction has been coordinated with the New Hampshire Department of Transportation; and has further assured the Commission that it possesses necessary easements for pole location on properties owned by the State of New Hampshire (Pole No. 1/13) and the State of Vermont (Pole No. 1/11); and

WHEREAS, NET indicates said pole line is temporary with all plant to be removed upon completion of bridge construction and relocation of the telephone plant to conduit within the bridge structure; and

WHEREAS, the Commission finds such construction of telephone plant in the public good; however, feels affected parties should be given an opportunity to respond in support of, or in opposition thereto; it is

ORDERED, that all persons desiring to respond to this NET petition be notified that they may file written comments or a written request for public hearing before this Commission no later than April 18, 1988; and it is

FURTHER ORDERED, that such notice be given by one-time publication of a summary of the petition in a newspaper having broad readership in the Walpole/Westminster area no later than April 11, 1988, and documented in an affidavit to be filed with this Commission; and it is

FURTHER ORDERED, *NISI*, that NET be, and hereby is, granted license under RSA 371:17 et seq to install, maintain and operate a 600-pair cable originating at Pole Number 1/13 in Walpole, New Hampshire, extending over and across the Connecticut River and terminated at Pole Number 1/11 in Westminster, Vermont; and it is

FURTHER ORDERED, that all construction meet the requirements of the National Electrical Safety Code; and it is

FURTHER ORDERED, that said pole line shall be removed upon completion of required bridge construction and appropriate replacement plant installed within the bridge; and it is

FURTHER ORDERED, that said authority shall become effective 15 days from the date of this order unless a hearing is requested as provided herein or the Commission otherwise directs.

By order of the Public Utilities Commission of New Hampshire this sixth day of April, 1988.

Re Public Service Company of New Hampshire

DR 86-41
Order No. 19,052

Re UNITIL Service Company
DR 86-69
Order No. 19,052

Re New Hampshire Electric Cooperative, Inc.
DR 86-70
Order No. 19,052

Re Granite State Electric Company, Inc.
DR 86-71
Order No. 19,052

Re Connecticut Valley Electric Company
DR 86-72
Order No. 19,052

New Hampshire Public Utilities Commission
April 7, 1988

ORDER resolving policy issues surrounding the translation of previously adopted avoided cost methodologies into purchased power relationships between electric utilities and qualifying cogeneration and small power production facilities.

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1. COGENERATION, § 25 — Rates — Avoided costs — Legal standards — LEEPA — PURPA.

[N.H.] The New Hampshire Limited Electric Energy Producers Act, RSA 362-A (LEEPA) and the Public Utility Regulatory Policies Act, 16 U.S.C. § 824a-3 *et. seq.* (PURPA) require the commission to establish rates for the sale of electric power to utilities that are (1) based on the utility's incremental cost of alternative electric energy and capacity, (2) nondiscriminatory, (3) just and reasonable to the consumers of the electric utility, and (4) in the public interest; both LEEPA and PURPA allow, but do not require, the commission to establish long term rates.
p. 122.

2. COGENERATION, § 25 — Rates — Avoided costs — Methodology for establishing rates.

[N.H.] In a proceeding to resolve polic issues surrounding the translation of previousl adopted avoided cost methodologies into pur chased power relationships between electri utilities and qualifying cogeneration and smal power production facilities, the commissio accepted the recommendation that it shoul establish a more flexible (negotiation based system for establishing rates paid to QFs tha that represented by standard utility-specific lon term rate offers; however, the commission con cluded that a flexible, negotiation-based systen could not be effectively implemented absent th development of a process whereby the commis sion could evaluate utility long term resourc needs.
p. 123.

3. COGENERATION, § 25 — Rates — Avoided costs — Methodology for establishin rates.

[N.H.] In a proceeding to resolve polic issues surrounding the translation of previousl adopted avoided cost methodologies into pu chased power relationships between electr utilities and qualifying cogeneration and sma power production facilities (QFs), the commi sion concluded that the QF industry in Ne Hampshire over the last ten years had deve oped to the extent that the commission r longer needs to offer standard long term leve ized rates in order to secure needed Q

capacity.
p. 125.

4. COGENERATION, § 25 — Rates — Avoided costs — Eligibility for rates — Project maturity.

[N.H.] In a proceeding to resolve policy issues surrounding the translation of previously adopted avoided cost methodologies into purchased power relationships between electric utilities and qualifying cogeneration and small power production facilities (QFs), the commission concluded that the high degree of speculation in the QF industry requires that criteria of project maturity be established to assure that projects obtaining rates and contracts will be able to provide capacity when it is needed.
p. 125.

5. COGENERATION, § 25 — Rates — Avoided costs — Eligibility for rates — Capacity limits.

[N.H.] In a proceeding to resolve policy issues surrounding the translation of previously adopted avoided cost methodologies into purchased power relationships between electric utilities and qualifying cogeneration and small power production facilities (QFs), the commission concluded that inasmuch as the supply of QFs is highly elastic at certain price levels there is a need to limit the amount of capacity eligible for any particular energy or capacity rate.
p. 125.

6. COGENERATION, § 25 — Rates — Avoided costs — Eligibility for rates — Diversity of resources.

[N.H.] In a proceeding to resolve policy issues surrounding the translation of previously adopted avoided cost methodologies into purchased power relationships between electric utilities and qualifying cogeneration and small power production facilities (QFs), the commission concluded that it must establish guidelines to ensure that the diversity of resource goals of the New Hampshire Limited Electrical Energy Producers Act are met.
p. 125.

7. COGENERATION, § 11 — Interconnection — Coordination of location decisions with system needs.

[N.H.] In a proceeding to resolve policy issues surrounding the translation of previously adopted avoided cost methodologies into purchased power relationships between electric utilities and qualifying cogeneration and small power production facilities (QFs), the commission concluded that it must assure that utilities provide sufficient information regarding load centers and transmission lines to make it possible for QFs to better coordinate their location decisions with the needs of the utility system.
p. 126.

8. COGENERATION, § 25 — Rates — Avoided costs — Eligibility for rates — Compatibility with integrated least cost resource plans.

[N.H.] Consistent with its determination that the development of the qualifying cogeneration and small power production facility (QF) industry should be encouraged within the context of overall utility long term resource planning, the commission directed that each utility file an integrated least cost resource plan in conjunction with an updated forecast of avoided costs; the plans, which must be updated on a biennial basis, must provide a comprehensive and detailed assessment of all reasonably available demand-side and supply-side utility investment options to satisfy ratepayers' energy resource needs at the lowest overall cost consistent with the reliable supply of electricity; the information developed through biennial updates to the plans will serve as a framework for QF long term rates and private negotiations.
p. 126.

9. COGENERATION, § 25 — Rates — Avoided costs — Establishment of rates — Resource planning — Forecasts.

[N.H.] As a means of assuring that the criteria and assumptions applied by electric utilities in their negotiations with qualifying cogeneration and small power production facilities (QFs) are the same as those used in judging their own resource options, and to ensure that QFs have access to the information they need to compete effectively with other resource options, the commission directed each utility to update its long term least cost resource plan with biennial filings containing reports and analyses concerning (1) forecast of future demands, (2) assessment of demand-side resource options, (3) assessment of supply-side resource options, (4) assessment of transmission constraints and requirements, (5) integration of demand-side and supply-side options, (6) two-year implementation plan and forecast designed to detail how its long term integrated least cost resource plan will develop, and (7) an updated forecast of avoided costs developed in a manner consistent with the above reports and analyses, which will provide the maximum price for all QF power purchase arrangements.
p. 126.

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION — 73 NH PUC

10. COGENERATION, § 25 — Rates — Avoided costs — Establishment of rates — Resource planning — Forecasts.

[N.H.] In determining the appropriate utility resource additions that can be potentially avoided by cogeneration and small power production facilities (QFs) and the megawatt amount of QF purchase power arrangements each utility should be seeking, the commission will review the adequacy and reasonableness of each utility's integrated least cost plan reports, as well its calculation of avoided costs.
p. 126.

11. COGENERATION, § 25 — Rates — Avoided costs — Establishment of rates — Resource planning.

[N.H.] If the commission determines that qualifying cogeneration and small power production facilities (QFs) cannot allow a generating utility to avoid any resources during the first eight years of its long term least cost integrated resource planning period, then that utility will be required to offer the QFs an as-available short-term energy and capacity rate.
p. 130.

12. COGENERATION, § 14 — Wheeling — Non-generating utilities.

[N.H.] In a proceeding to resolve policy issues surrounding the translation of previously adopted avoided cost methodologies into purchased power relationships between electric utilities and qualifying cogeneration and small power production facilities, the commission decided to continue the existing arrangement whereby non-generating utilities have the option of either purchasing power from QFs or wheeling it at no charge to their requirements supplier.
p. 131.

13. COGENERATION, § 25 — Rates — Avoided costs — Methodology for establishing rates.

[N.H.] If the commission determines that qualifying cogeneration and small power production facilities (QFs) have the potential to allow a generating utility to avoid investment in additional resources during the first eight years of the utility's long term least cost integrated resource planning period, then the commission will require long term commitments between the utility and QFs; specifically, the utility would be required to make a standard offer to smaller renewable resource QFs and to individually negotiate with large and/or non-renewable resource based projects.
p. 131.

14. COGENERATION, § 24 — Rates — Eligibility for long term standard offer.

[N.H.] If the commission determines that purchases from qualifying cogeneration and small power production facilities (QFs) can displace a utility resource option, then the utility must make available long term standard offers for those QFs that have an installed capacity of 100 to 1000 kilowatts *and* are based on renewable resources; in order to be eligible to apply for the standard offer, the QF must demonstrate the following indications of project maturity site control, Federal Energy Regulatory Commission license or exemption, approved necessary state environmental and local permits, a detailed plan of the proposed financing for the project, a plan of construction including a timetable, and plans or agreements for the reliabl

operation of the project during the term of the standard offer.
p. 131.

15. COGENERATION, § 25 — Rates — Avoided costs — Methodology for establishing rates — Standard offers.

[N.H.] Long term standard offers made available to qualifying cogeneration and small power production facilities by utilities must incorporate the following characteristics: (1) the rate must be equal to the projected cost of the avoidable resource identified in the generating utility's long run integrated resource plan; (2) the term of the rate should be the lesser of 15 years or 3 years beyond the term of the QF's financing; and (3) the offer must permit QFs to apply for rates whose initial years are the first three years of the stream of the adopted avoided costs.
p. 131.

16. COGENERATION, § 25 — Rates — Avoided costs — Methodology for establishing rates — Negotiations.

[N.H.] Electric utilities were directed to establish a private contracting and negotiation procedure for all qualifying cogeneration and small power production facilities (QFs) that are larger than 1000 kilowatts and/or based on fossil fuel: specifically, utilities must (1) identify the megawatt amount of utility resources in its integrated resource plan than can be displaced or delayed following a projection of QF capacity available under the as-available short term rates and its long term standard offer, and (2) develop and implement a procedure for negotiating with QFs offering to provide energy and capacity.
p. 132.

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i. COGENERATION, § 25 — Rates — Avoided costs — Methodology for establishing rates.

[N.H.] Discussion, by the commission, of how the evolution of the commission's rate-setting policy concerning utility purchases from qualifying cogeneration and small power production facilities (QFs) and the development of the QF industry have led to the need to translate previously adopted avoided cost methodologies for setting rates into purchased power relationships between electric utilities and QFs.
p. 123.

APPEARANCES: As previously noted.

By the COMMISSION:

I. PROCEDURAL HISTORY

On February 7, 1986 Public Service Company of New Hampshire (PSNH) petitioned for a comprehensive avoided cost rate proceeding. PSNH's petition requested, *inter alia*, that the commission: 1) open a proceeding to review the terms, conditions and rates established in *Re Small Energy Producers and Cogenerators*, Docket No. DE 83-62, 69 NH PUC 352, 61 PUR4th 132 (1984)(DE 83-62); 2) establish consistent terms, conditions and avoided cost methodologies for sales by qualifying small power producers and qualifying cogenerators (qualified facilities or QFs) to all New Hampshire electric utilities; 3) update the rate determined in *Re Small Energy Producers and Cogenerators*, Docket No. DR 85-215, 70 NH PUC 753, 69 PUR4th 365 (1985)(DR 85-215); and 4) decline to accept long term rate filings submitted after February 7, 1986 until the issues raised in the petition were adjudicated.

By Order of Notice dated February 26, 1986, the commission opened Docket No. DR 86-41, Re *Public Service Co. of New Hampshire Avoided Costs* for the purpose of investigating the terms, conditions and denied the following PSNH requests:

1) that the commission consider terms, conditions and avoided cost methodologies for electricity sales by QFs to all New Hampshire electric utilities in the context of a single docket;

2) that the long term rates determined in DR 85-215, be updated in the context of this docket rather than following the previously determined annual update time frame; and

3) that the commission decline to accept long term rate filings submitted after February 7, 1986 pending resolution of the matters to be adjudicated in this proceeding.

Rather, also on February 26, 1986, the commission opened a series of separate dockets to examine the terms conditions and avoided cost methodology for the remaining electric utilities: Docket Nos. DR 86-69, the UNITIL Companies (UNITIL); DR 86-70, the New Hampshire Electric Cooperative (NHEC); DR 86-71, Granite State Electric Company (GSE); and DR 86-72, Connecticut Valley Electric Company (CVEC). On September 23, 1986, by report and order no. 18,407 (71 NH PUC 547), the commission consolidated the cases for purposes of hearing and subsequently adopted the proposal by the parties presented at the January 19, 1987 procedural hearing for a three phase hearing schedule. In Phase I, the parties to the settlement agreement concerning the technical development of avoided cost presented and defended their stipulated methodology while PSNH presented contrary evidence and argument. Phase II would have occurred only if the commission rejected the settlement agreement. Phase III of the proceeding dealt with the policy issues surrounding the translation of the avoided cost methodology adopted in Phase I into a commission rate and/or alternative policies for establishing the purchased power relationships between the utility companies and the QFs.

On September 14, 1987 the commission issued report and order no. 18,829 (72 NH PUC 396), which set out the detailed procedural history of the dockets, adopted the stipulated avoided cost methodology both for the utilities that had signed the settlement agreement and for PSNH, ordered PSNH to file avoided costs consistent with the findings in the commission report, and deferred consideration of specific aspects of NHEC's avoided costs to Phase III.

The commission held hearings on Phase III of this proceeding on August 3-6, 17 19 and 21, 1987. The parties filed initial briefs on October 14, 15 and 16, 1987, and GSEC filed a reply brief on October 30 1987.

II. POSITIONS OF THE PARTIES

The utility companies generally emphasized the need to create a system that encourages direct negotiations between utilities and QFs, private contracting, flexibility and the use of avoided cost as a reference for negotiated contracts rather than the formula for a commission-set standard rate offer. While CVEC gave moderate support to the establishment of a formal bidding system, most companies argue that such a system lacks the flexibility of private negotiation, particularly once the bids have been formally accepted, and is cumbersome, especially in light of the small amount of additional capacity needed by each individual company. UNITIL, although not supporting a formal bidding system, did recommend that the commission adopt a specific framework fo negotiations, observing that "QFs require a well defined process so that they can efficiently structure their own planning and proposals on a competitive basis" and that "QFs may be concerned that an unstructured private negotiation system also provides insufficient mechanisms and safeguards to discourage unfair dealing." UNITIL Brief at 12.

The utilities recommended annual updates of avoided cost and reports to, and review by, the commission on each utility's progress in contracting with QFs. The companies recommend that only if the commission finds that the progress of negotiations by individual utilities is unsatisfactory should it establish long term purchase power rates or "employ its powers under RSA 362-A to persuade, even compel them to join the parade." GSE Brief at 14.

If the commission establishes rates, the utilities advocate limitations on the size of each QF and the aggregate capacity to be added in each year, restrictions on the amount of front-end loading related to each project's capital costs or equity investment, and the adoption of specific provisions for security. Additionally, NHEC recommends that the length of the rate term be limited to ten years, that the commission specify the minimum terms and conditions that should be contained in most negotiated agreements and that the commission retain the option that distribution companies may wheel QF power to their wholesale supplier at no charge.

Pinetree argues that the methodology of DE 83-62 should not be completely disregarded but should be modified. It recommends a methodology that combines the calculation of avoided costs at various increments and the queuing of applicants. It also suggests that the commission retain and expand its requirements for QF eligibility for long term rates and adopt a system of milestones with respect to project development.

Pinetree agrees, however, that "private contracting is a viable alternative provided appropriate guidelines and safeguards are developed and made applicable for the process." Brief at 10. Pinetree requests that the commission establish "a schedule of avoided costs, encourage the implementation of private negotiated contracts between SPP and utilities, and hold that the terms and conditions established in DE 83-62, with certain modifications ... are presumptively reasonable." Brief at 17. Its suggested modifications relate to the adoption of milestones with respect to project development.

The Consumer Advocate did not submit a Brief, but endorsed a bidding system in the proceedings through a witness who presented the frameworks for bidding as adopted by other New England commissions and particularly commended the Massachusetts system.

III. COMMISSION ANALYSIS

[1] The purpose of Phase III of the instant proceeding is to resolve the policy issues surrounding the translation of the avoided cost methodology adopted in Phase I into purchased power relationships between utility companies and QFs. Such policy will continue to fulfill the commission's responsibilities under the New Hampshire Limited Electrical Energy Producers Act, RSA Chapter 362-A as amended (LEEPA), and the Federal Public Utility Regulatory Policies Act, 16 U.S.C. §824a-3 *et. seq.* (PURPA). These acts require the commission to establish rates for the sales of electric power to public utilities that are (2) based on the utility's incremental cost of alternative electric

energy and/ capacity, (2) non-discriminatory, (3) just and reasonable to the consumers of the electric utility, and (4) in the public interest. Both allow, but do not require, the commission to establish long term rates.

[2] In reviewing the record before us, we note that there is broad consensus among the parties that the policy established by the commission emphasize flexibility and encourage direct negotiation between the utilities and the QFs. The utilities suggest that the commission review the progress of negotiations and impose long term purchase power rates only if it finds that progress unsatisfactory. The commission accepts the recommendations of the parties that, at least initially, it institute a more flexible system than that represented by standard utility-specific long term rates offers.

However, we do not believe that such a system can be effectively implemented absent a commission approved framework for those flexible negotiations. We find that the proper goal for the commission policy regarding short term and long term utility purchases of energy and capacity from QFs is the integration of QFs into the utility's own long term resource planning in an efficient and equitable manner. Therefore, the necessary framework for utility negotiations with QFs must be that utility long term resource planning. One necessary outcome of these proceedings is the need to develop and implement a process in which the commission can evaluate all demand-side and supply-side resource additions, including QFs, to the utilities, systems.

The following analysis will first briefly review the evolution of commission policy and the QF industry in New Hampshire that resulted in the contextual setting for the instant order. Next we will specify the reports and analysis of the resource plan that the commission will require each utility to file and support in order that a utility-specific, commission approved framework for utility-QF negotiations can be formulated. Last, we will delineate the process and rates, terms and conditions of purchase power arrangements available within that framework.

A. *Evolution of commission policy and the QF industry*

[i] Following the passage of the LEEPA and PURPA legislation in 1978, the commission set rates and established interconnection standards, first for PSNH as the state's only generating utility and subsequently for the state's non-generating utilities. These early orders determined shor term buy back rates for energy and capacity for all utilities, and offered non generating utilities the option of eithe paying their generating suppliers' avoidec cost or wheeling to their suppliers at nc charge. Although the commission alsc encouraged utilities to negotiate long tern purchase power agreements with develop ers, only PSNH responded, signing lon term contracts primarily with smal hydro-electric facilities. Between 197 and 1983, 57 facilities achieved commer cial operation; they were predominantl run of the river hydro-electric (41), bu also residential wind (1), wood cogeneration (4) and photovoltaic (1).

In the spring of 1983, the Nev Hampshire Legislature amended LEEPA to redefine qualifying facilities to cover al technologies that qualify under PURPA (including fossil fuel based cogeneration which had not previously qualified unde LEEPA) and specifically grant the com mission the authority to establish a lon term purchase power rate. Pursuant to th amended statute, the commission opened DE 83-62 to reconsider the methodology for setting PSNH's short term rates and formulate its long term rates for the first time. Following extensive settlement discussions among staff, PSNH and QF developers, in June 1984 the commission adopted the new methodology and procedures for both the short term and permanent long term rates. Under the DE 83-62 rates, the commission approved 105.786 MWs of capacity, some of which reflects the shift by a few facilities previously receiving short term rates to a long term commitment for sale of energy and capacity to PSNH.

In September 1985, in DR 85-215 the commission revised the long term rates and the short term capacity rate by inserting updated data into the methodology established in DE 83-62. However, the growing disparity between the DR 85-215 rates and the cost of developing projects based on lower interest rates and, for cogenerators, declining fossil fuel rates of late 1985 and early 1986, enhanced the economic feasibility of projects that could develop on DR 85-215 rates. In the first four months of 1986, facilities representing the following amounts of capacity petitioned the commission for a long term rate pursuant to DR 85-215:

January	41.60 MW	
February	124.96 MW	(plus a 49.5 MW rejected filing)
March	166.50 MW	(plus a 55 MW rejected filing and 20 MW filing that was subsequently withdrawn)
April	204.98 MW	
May	45.82 MW	
Total	583.86 MW	

Partially as a result of the magnitude of the capacity offered by QFs, PSNH petitioned in February 1986 that the commission open the instant dockets. In addition to these generic dockets regarding rates, terms and conditions of the utility/QF power purchase arrangements, throughout 1986 the commission held hearings on the petitions by individual QF developers. Issues addressed in these hearings included project maturity required at the time of filing for a long term rate, the eligibility of third party fossil fuel cogenerators for long term rates especially if levelized, the extent of New Hampshire's wood resource and the financial and managerial ability of the sponsors of wood-electric projects to develop multiple sites within the schedules for which they had petitioned. The commission eventually approved 140.465 MW of capacity pursuant to the DR 85-215 rates:

Technology	*No. Facilities*	*Gross Capacity*
Hydro	23	16.665
Wind	0	0
Wood/Cogen	5	66.2
MSW	4	37.6
Multi-Fuel	1	20.0
Total		140.465

Of these, one MSW project subsequently withdrew its petition in order to sign a private contract (PRS — Derry at 10.3 MW) and the rate for a second project was rescinded for failure to meet the milestones that were a condition of its rate (Vicon at 13 MW).

The DR 85-215 rates were updated in DR 86-134 in July 1986. However, one result of the on-going settlement discussions in the avoided cost methodology dockets, was the realization that the DE 83-62 methodology was inadequate to deal with the then existing QF environment. The methodology of the rate calculation assumed PSNH load forecasts, identified an hourly margin of generating units and calculated rates based on the savings achieved when PSNH could avoid operating those units. The methodology did not anticipate the changes in the margin that resulted from the lower load forecast due to the loss of the UNITIL companies as wholesale customers and the addition of significant amounts of QF capacity to the generating mix. Concerned that additional filings under DR 86-134 would only exacerbate the methodological problem and interfere with the investigation into the methodology, the commission suspended DR 86-134 in September 1986.

An outgrowth of the consideration of the petitions filed under DR 85-215, was the adoption of a ranking of categories of QF projects based on their contribution to the public good. The commission accepted the guidance in LEEPA in regard to the state's emphasis on renewable resources and in PURPA on the need to foster a decreased dependence on fossil fuels, and especially on foreign oil, and found that "[n]either [LEEPA nor PURPA] was intended to increase the dependence, particularly of New England, on fossil fueled electrical generation, however efficient that increased generation may be." The commission further noted that "wood and MSW projects have positive externalities that are also in the public interest." Report and Order No. 18,530 at 9 (72 NH PUC 8, 10, 11).

[3] This ten year evolution of the QF industry and commission policy in New Hampshire has resulted in a context for the instant order that bears several distinct characteristics. First, the QF industry in New Hampshire is no longer a fledgling industry that needs to be specially encouraged. The number and size of projects pro posed and/or approved clearly reflects tha New Hampshire possesses a diversifie and well-established QF industry with a strong entrepreneurial spirit that will mak available new capacity whenever it is eco nomic to do so. One specific implication o the maturity of the QF industry is that th commission does not need to continue t offer standard long term levelized rates i order to secure capacity needed sometim in the future but not in the present.

[4] Second, based on the projects tha have come before us, it is clear that ther is a high degree of speculation in the Q industry. Criteria of project maturity mus be established to assure that the project obtaining rates and contracts will be abl to provide capacity when it is neede Only by establishing criteria for maturit at the time of application and monitorin milestones of development can the com mission, utilities and ratepayers reason ably rely upon QF project proposa materializing into operating units that wi meet the state's long term energy an capacity needs.

[5] Third, the methodology as adopte in DE 83-62 must be modified at least the extent of providing a better congru ence between the amount of capacity mea sured when the value of capacity is bein calculated, and the amount of capaci eligible for the rate based on that calcu lated value. Since the supply of QFs highly elastic at certain price levels the is a need to limit the amount of capaci eligible for any particular energy a capacity rate.

[6] Fourth, the QF industry, in terms technology, size and location, will n automatically maximize the potenti benefits to New Hampshire's electric uti ties and ratepayers. The original Declar

tion of Purpose in LEEPA states:

> It is found to be in the public interest to provide for small scale and diversified sources of supplemental electric power to lessen the state's dependence upon other sources which may, from time to time, be uncertain.

At any point in time, cost relations may favor a particular technology and economics of scale may encourage an increase in size of individual facilities. If the commission is to ensure that the goals of the LEEPA legislation will be realized, and that the QFs that enter into purchase power arrangements are in fact "small scale and diversified" in relation to each utility's generation mix, the commission must establish guidelines for the categories of facilities it believes best satisfies those goals.

[7] Finally, developers do not choose to locate their facilities based on a coordinated decision to maximize the utilities' highly integrated generation/transmission systems. While some projects are limited to very specific locations (*e.g.* low head hydroelectric), other projects have available greater choice of location. The commission must assure that utilities provide sufficient information regarding load centers and transmission lines that will make it possible for the QFs to better coordinate their location decisions with the needs of the utility system.

B. *Reports of the resource plan and analysis required to establish the framework for QF rates and negotiations*

[8-10] Given the goal that further encouragement of the QF industry be in the context of overall utility long term resource planning, it is necessary to institute a consistent process to enable the commission to evaluate all utility resource investment options including purchases of QF power. Therefore, each utility will be required to file an integrated least cost resource plan in conjunction with updated forecast of avoided costs in order that the commission may reasonably review each utility's planning process, resultant plans, and avoided cost forecast. The objective of the integrated least cost resource plan is to satisfy future demand with the optimal combination of supply-side resources and demand-side programs. Thus, the plan must provide a comprehensive and detailed assessment of all reasonably available demand-side and supply-side utility investment options to satisfy ratepayer's energy service needs at the lowest overall cost consistent with the reliable supply of electricity. Overall cost in this context includes compliance with public policies in regard to environmental and social concerns as well as financial considerations.

We will require the utilities to provide the reports and analyses of the integrated least cost resource plan to the commission by April 15th, biennially in even numbered years. Based on these reports and information developed through testimony, the commission will establish a framework for QF long term rates and private negotiations. As further discussed herein, this framework contemplates a much expanded role for private negotiation between QFs and utilities, based on utilities' long term resource planning. Our endeavor is to create a public forum in which the utilities explain their planning criteria and assumptions. This forum will both ensure regulatory oversight of the resource plans and make available information needed by QFs to compete effectively with the utilities' other resource options. It will also ensure

that the criteria and assumptions applied by the utility in negotiations are the same that it uses to judge its own resource options.

In the biennial filing each utility shall develop and support the following seven areas of major reports and analysis and such additional areas as the commission may notice.

1) Forecast of future demands
2) Assessment of demand-side options
3) Assessment of supply-side options
4) Assessment of transmission constraints and requirements
5) Integration of demand-side and supply-side options
6) Two-year implementation plan and forecast
7) Avoided cost forecast

These seven areas of analysis require assumptions and forecasts of the future. The utility must forecast the demand for electricity, the various utility supply-side and demand-side resource options available to meet this demand, and the prices and rate inputs associated with plausible planning scenarios. Additionally, the utility should assess, and explicitly treat in the analysis, the risk and uncertainty of the forecast scenarios and their sensitivity to various assumptions. These reports should be consistent with the Annual Report filed with the Bulk Power Supply Facilities Committee and other reports and analysis used by the utilities for ratemaking and investment decisions. Finally, each utility will derive an updated forecast of avoided costs consistent with the other reports and analysis contained in the filing.

1) Forecasts of Future Demands

Each utility will file a 15 year forecast of capacity and energy, at the pare and/or full requirements supplier level aggregation as well as at the subsidia and/or distribution level. The utilitie should file a minimum of three forecas representing a plausible range — hig low, and "probable" — with the probab to represent the utility's most likely set future events. The various forecasts shou be utilized to show the sensitivity resource option scenarios to varying leve of demand in the treatment of risk a uncertainty. While we will not prescribe forecasting methodology at this time, will require that the methodolo employed by each utility be able to eval ate the effect of price and demand-si resource planning decisions (*i.e.* conserv tion, load management) on the forecast future demands. Further, the forecasti methods employed by each utility sho be consistent with methods used by t utility for other corporate planning a investment decision making.

2) Assessment of Demand-Side Optio

The integrated least cost resource pl should demonstrate that the utility and, its power requirements supplier has a quately assessed all reasonably availa utility sponsored demand-side resou options to satisfy ratepayers' energy s vice needs. Each utility should deve and implement costs and benefits tests evaluating and ranking potential new u ity sponsored conservation and load m agement programs. The demand-s option assessment should include an ex cit accounting of price induced dem reductions, and reductions in demand fr the continuation of existing utility government sponsored demand-side p grams. The commission expects that e utility will make use of the plethora demand-side program information and data available in the electric utility industry. The objective of the assessment is to identify all cost-effective demand-side options.

3) Assessment of Supply Options

Each utility should assess the wide range of utility supply-side resources available to meet ratepayers future energy service needs, including plant re-powering or life extension, bulk power purchases, non-traditional utility generation sources, and conventional plant construction. The utility may include an assessment of the expected amount of QF capacity to be provided under existing arrangements and/or power on an as-available basis; however, incremental firm QFs should be excluded from the supply assessment and the utility's resource plan. The utility should employ a variety of models or methods to assess these supply options, including production costing and reliability models as well as risk analysis models or methods. We will require that the minimization of the present worth of future revenue requirement form a basic criterion used to select and prioritize these supply options.

4) Assessment of Transmission Requirements, Limitations and Constraints

Each utility should provide a detailed assessment of the forecasted transmission requirements, limitations and constraints over the planning period. This assessment should include a map indicating load center concentrations, transmission limitations and constraints, and planned and proposed changes to the transmission system within the franchise area during the forecast period. The utility should provide an evaluation of how new generation, regardless of ownership, will be incorporated into the transmission grid and the consequences of additional generating sources for the transmission system.

5) Integration of Demand-Side and Supply-Side Resource Options

Each utility should develop a formal process for the integration of cost effective utility sponsored demand-side programs and supply-side resource options and demonstrate that the utility has considered all aspects of its resource needs. Under this process demand-side programs and supply-side resource options should be evaluated in a dynamic iterative process that considers risk, sensitivity, and uncertainty factors. The objective of this analysis is to determine the optimal mix of resources that will provide ratepayers' energy service needs at the least cost consistent with the reliable supply of electricity.

6) Two-Year Implementation

The commission requires that each utility submit a consistent two-year "action" plan designed to detail how the long term integrated least cost resource plan will be developed and implemented in the first two years. This action plan should include a short-term forecast (2-year) of capacity and energy requirements at the parent and/or full requirement supplier level as well as at the subsidiary and/or distribution utility level of aggregation. The utility should demonstrate how the optimal "mix" of utility sponsored demand-side programs and supply-side resources will be developed and implemented during the forthcoming two year planning period. The plan should specify all new and existing models, data, equipment, personnel, and

facilities that the utility intends to utilize and/or require in the implementation of the plan.

7). Avoided Cost Forecasts

In conjunction with biennial filing of the reports and analysis discussed above each utility will file a 15 year forecast of avoided cost and all supporting data. This forecast should be based on the utility's most likely scenario as identified in these reports and analysis. Further, the methodology for forecasting avoided costs should be consistent with the methodology adopted by this commission in Phase I. However, unlike the Phase I settlement process, the calculation of avoided costs will derive from the respective utility's integrated least cost resource plan as reviewed by the commission in a biennial update proceeding that will follow the filing of the reports and analyses. Those avoided costs will provide the maximum price for all QF purchase power arrangements. As further discussed below, QF purchase power rates under this policy will vary according to whether or not a utility will potentially be able to defer or cancel some future utility resource because of QF power.

By deriving each utility's avoided costs from an integrated least cost resource plan we ensure that the Phase I methodology will identify the most cost-effective way that the utility could generate power to meet its system requirements in the absence of QFs. Such cost-effective resource additions will constitute the costs that are potentially avoidable by QFs. In the alternative, if the integrated least cost resource plan does not identify any future utility resources that the QF can displace, the avoided costs would be based on the properly calculated short-run avoided costs of the utility.

Under the Phase I methodology, t short-run avoided cost of the utility wou be determined by using the decreme method in the production costing modeli of the utility. This method requires tv production costing runs. The first run is simulation of production costs withc incremental QF as a "base case"; the se ond run, involves the reduction of load the amount of the decrement adopted each utility in Phase I. As discussed in c report in Phase I of this docket the dec ment method is analogous to the definiti of avoided costs in that it calculates difference in cost with and without specified block of QF power.

In the alternative, if the utility were a to defer or cancel some future resou addition because of the availability of power, then the avoided costs would based on the capital and operating costs those avoidable utility resources. T Phase I methodology incorporated operating cost and capitalized energy s ing of a new base load Integrated Gasif Combined Cycle (IGCC) proxy or ref ence unit as the avoidable resource t QFs could allow all the utilities to avo The crux of the integrated least cost pl ning derivation of avoided costs that envision herein is the identification each utility of the proxy or refere unit(s) that would be cost effective w added to the utility's system and would potentially avoidable by purchases of power. That is, such an avoidable proxy reference unit should be incorporated each utility into its avoided cost estin at the point that it is the least cost resou option as identified in the utility's bien filing.

C. *Commission Hearing and Review*

The commission will hold hearings and will review, *inter alia*, the adequacy and reasonableness of each utility's integrated least cost plan reports and analysis as well as the calculation of avoided costs. If the utility does not anticipate the need for additional utility resources that the QF can displace within the first 8 years of the planning horizon, it will file the following information:

1. Testimony to demonstrate that assessment.

2. Testimony documenting the company's integrated least cost resource plan for providing all aspects of its energy resource needs.

If following our review of the utility's integrated least cost resource plan the commission finds that no utility resources can be potentially avoided by QFs in the first 8 years of the forecast period, the commission will not require the utilities to develop and implement a long term purchase power negotiation procedure.

If the utility's integrated resource plan identifies additional utility resources that are potentially avoidable by purchases from QFs within the first 8 years of the planning horizon, the utility will file the information required above plus:

3. Testimony documenting a private contracting and negotiation procedure for securing purchase power arrangements with QFs.

Based on our review of the various reports, analyses and testimony, the commission will determine the appropriate utility resource additions that can be potentially avoided by QFs, and, if any, the MW amount of QF purchase power arrangements each utility should be seeking.

D. *Process and Rates, Terms and Conditions of Purchase Power Arrangement*

[11] 1). Pricing when the commission determines that QF purchases cannot displace a utility resource option

If the commission's determination is that QFs cannot allow the utility to avoid any resources during the first eight years of the planning period the utility will only be required to offer QF's an as-available short-term energy and capacity rate. Thus, if the utility does not require long term capacity and the only benefit of new QF power is fuel savings/source diversity and the sale of capacity into NEPOOL, the utility will only be required to offer QF's the as-available short term energy and capacity rate.

Therefore all utilities are required to file short term rates in conjunction with their Fuel Adjustment Clause/Purchase Power Cost Adjustment or Energy Cost Recovery Mechanism proceedings (presently once a year for ConVal, every six months for all other utilities). The short term energy and capacity rates should be calculated consistent with the methodology adopted in Phase I. Therefore, the energy rate should be calculated using the production costing decrement method adopted in Phase I, so that each utility's biennial short term avoided cost forecast report will provide the utility's "most likely" projection of short term avoided costs rates. The short term capacity rate should be based on the utility's best estimate of the market value of peaking capacity in NEPOOL. QF capacity eligible for capacity payments will be determined by the commission according to standards set forth in Dockets

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DE 78-232, DE 78-233, and DE 79-208.

[12] The commission will continue the existing arrangements established in *Re Purchases for Non-generating Utilities*, 67 NH PUC 825 (1982), whereby non-generating utilities have the option of either purchasing the power or wheeling it at no charge to their requirements supplier. However, we will monitor purchases by utilities on the short term rate. Of particular interest will be each utility's choice of purchases at the subsidiary versus parent, distribution company versus generating supplier levels, especially in relation to the wholesale rate. The commission acknowledges the potential problems of system reliability stability and transmission when very large QFs are added to the smaller systems or load centers. However, we put the utilities on notice that we do not intend our wheeling policy to relieve the distribution companies of their obligation to obtain the least cost supply consonant with system reliability for the benefit of their ratepayers.

2). Pricing when the commission determines that QF purchases can displace a utility resource option

[13] If following review of the utility's biennial integrated least cost resource filing the commission finds that additional utility resources in the first 8 years of the forecast period are potentially avoidable by QFs, the commission will require long term commitments between QF's and utilities. The commission will hereby require the companies to establish a two-tiered program, and distinguish between the small renewable projects that were the original focus of LEEPA and that add to the diversity of the New Hampshire supply mix, and the projects that are larger and/or based on non-renewable fuel sources. We also note that the transaction costs for individual negotiations can overwhelm any benefits of commitments with smaller projects for both the developer and the utility. Therefore we will require utilities to make a standard offer to the smaller projects based on renewable resources while individually negotiating with projects that are larger and/or based on non-renewable fuel sources.

a. *Standard Offer*

[14, 15] i. Projects less than 100 KW may be developed only on the standard short term rate.

ii. Utilities will be required to make available long term standard offers fo those projects that have an installed capacity of 100-1000 KW *and* are based o renewable resources. In order to be eligible to apply for the standard offer, the QI must demonstrate the following indications of project maturity: site control FERC license or exemption (hydroelectric), approved necessary state environmental and local permits, a detailed pla of the proposed financing for the project, plan of construction including a timetable and plans or agreements for the reliabl operation of the project during the term o the standard offer. While projects are eligible for full avoided costs, any front en loading must be negotiated with the utilit In no case will the project's total front en loading exceed the project's capital cos Further, the QF must provide a cash c cash equivalent security equal to 10% c the expected total front end loading.

Each utility will file with the commis sion a standard contract format includin the terms and conditions of the intercor nection and the power purchase. The sta dard agreement will specify the timing payments by the QF for the interconne tion study and the interconnection.

The standard offer must incorporate the following characteristics. The rate will be equal to the projected cost of the avoidable resource(s) identified in the generating utility's long run integrated resource plan. The term of the rate should be the lesser of 15 years or 3 years beyond the term of the QF's financing. QF's may apply for rates whose initial years are the first three years of the stream of the adopted avoided costs.

b. *Private Contracting and Negotiation*

[16] The utilities will establish a private contracting and negotiation procedure for all other QF's larger than 1000 KW and/or based on fossil fuel.

The utilities will identify the MW amount of utility resources in its integrated resource plan that can be potentially displaced or delayed following a projection of QF capacity available under the as-available short term rates and its long term standard offer. Based on the guidelines established by the commission following the hearing on the utility's biennial integrated least cost resource filing, the utilities will develop and implement a procedure for negotiating with QF's offering to provide energy and capacity. The negotiations will use as a benchmark the projected cost of the avoidable resource(s) identified in the generating utility's resource plan, but are not required to contract at full avoided cost nor adhere to the specific terms and conditions of the standard contract. Negotiable terms may include *inter alia*, price, front end loading, security arrangements, dispatchability, and timing of the QF capacity addition. The utilities will file the negotiated contracts with the commission. They will also provide an annual report on the status of negotiations with QF's including both the committed capacity and rejected proposals.

The commission notes that the utilities retain their obligations to provide safe and reliable service to their ratepayers. These obligations include the provision by the utility of adequate supplies of capacity as required. Thus, it remains the responsibility of the utility to monitor its supply of capacity, from QFs as well as other sources, to assure that the capacity is available as needed. To this end the utilities should formulate milestones during the development stage as well as performance reviews for QF's that have attained commercial operation. These milestones and performance reviews should apply to all QFs, both those on standard offers as well as those under negotiated contracts.

The commission will schedule a workshop for the parties in the instant docket for the purpose of establishing a timetable and addressing any questions concerning the utility's biennial integrated least cost resource filing. For the year 1988 we are waiving the requirement that the plan must be filed by April 15, 1988.

Our Order will issue accordingly.

ORDER

Upon consideration of the foregoing Report on Phase III, which is made a part hereof, it is hereby

ORDERED, that the policy issues surrounding the translation of the PHASE I and II avoided cost methodology into long term purchase power arrangements between the state's electric utilities and QFs shall be as provided for in the foregoing report; and it is

FURTHER ORDERED, that consistent with this policy, each utility shall provide the reports and analysis (including updated long term avoided cost estimates) of the

integrated least cost resource plan to the commission by April 15th, biennially in even numbered years; and it is

FURTHER ORDERED, that the April 15th, 1988 filing date required by this report and order is hereby waived pending a workshop for the parties to establish timetables and address questions concerning the instant order; and it is

FURTHER ORDERED, that the commission will direct its staff to contact the parties to this proceeding for purposes of scheduling said workshop within one month of the date of this order.

By order of the Public Utilities Commission of New Hampshire this seventh day of April, 1988.

Re Southern New Hampshire Water Company

Additional party: Manchester Water Works

DE 87-217
Order No. 19,053

New Hampshire Public Utilities Commission
April 8, 1988

ORDER amending prior decision approving wholesale water and construction agreements. For prior order see 73 NH PUC 81.

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1. WATER, § 12 — Construction and equipment — Improvements to distribution system — Allocation of costs — Construction agreement.

[N.H.] In reviewing a contract between two water utilities for the construction of water facilities, the commission found that to the extent that larger water mains that constituted excess capacity to the first utility were used and useful to the second utility, the mains would be viewed as improvements made to the second utility's distribution system, and the first utility would be allowed credit for the cost of those improvements.
p. 135.

2. VALUATION, § 211 — Excess capacity — Rate base disallowance — Water utility.

[N.H.] Where a water utility did not prove that 16-inch water mains were necessary for the provision of service, it was found imprudent for the utility to have negotiated the provision of the contract that obligated it to pay for a larger main than was necessary to serve its customers; therefore, the costs associated with the difference between the larger mains allowed under the contract and those found necessary by the commission, were disallowed from the utility's rate base until such time as the utility could prove that larger mains were a reasonable choice in the provision of service to its customers.
p. 135.

By the COMMISSION:

REPORT ON MOTION FOR REHEARING

This report concerns a joint motion fo rehearing by Southern New Hampshir Water Company and Manchester Wate Works of *Re Southern New Hampshir Water Co.* DE 87-217, report and order nc 19,021 (February 25, 1988) (73 NH PU 81). In that order we approved the prc posed wholesale water and constructio agreements subject to certain exception Upon consideration of the motion w affirm our approval of the contract b alter our decision concerning the excej tions.

The following is a discussion of tl relevent factual background. On Octob